CITY OF LODI

COUNCIL COMMUNICATION

AGENDA TITLE: United States Department of Energy Western Area Power Administration (Western) Central Valley Project, California Contract for Electric Service Base Resource with City of Lodi (Contract).

MEETING DATE: July 15, 2000

PREPARED BY: Electric Utility Director

RECOMMENDED ACTION: That the City Council authorize the City Manager to execute the attached Contract.

BACKGROUND INFORMATION: The Contract is intended to give Western's customers certainty that they will have access to Federal power, with time to develop details of Western's Marketing Plan before 2005.

Many factors such as the final outcomes of Western's and Lodi's joining the California Independent System Operator (ISO), PG&E and Western's Contract 2948A, etc., will have a final bearing on subsequent Contract specifics. Based on past experience, the City of Lodi's allotment of Western power has been and continues to be an important element of the City's total power resources

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FUNDING: Bulk Purchase Power 160642.8201 (after power is delivered under the Contract)

Funding Approval: Vicky McAthie
Vicky McAthie, Finance Director

Alan N. Vallow
Alan N. Vallow
Electric Utility Director

PREPARED BY: Jack Stone, Manager, Business Planning and Marketing

ANV/JS/lst

C: City Attorney
Finance Director

APPROVED: H. Dixon Flynn
H. Dixon Flynn - City Manager

RESOLUTION NO. 2000-129

A RESOLUTION OF THE LODI CITY COUNCIL AUTHORIZING THE CITY MANAGER TO EXECUTE THE UNITED STATES DEPARTMENT OF ENERGY WESTERN AREA POWER ADMINISTRATION CENTRAL VALLEY PROJECT, CALIFORNIA CONTRACT FOR A RIGHT TO PURCHASE ELECTRIC SERVICE UNDER THE 2005 POWER MARKETING PLAN WITH THE CITY OF LODI

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BE IT RESOLVED that the City Manager is hereby authorized and directed to execute the United States Department of Energy Western Area Power Administration Contract on behalf of the City of Lodi.

Dated: July 19, 2000

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I hereby certify that Resolution No. 2000-129 was passed and adopted by the City Council of the City of Lodi in a regular meeting held July 19, 2000, by the following vote:

AYES: COUNCIL MEMBERS – Hitchcock, Land, Nakanishi, Pennino and Mann (Mayor)

NOES: COUNCIL MEMBERS – None

ABSENT: COUNCIL MEMBERS – None

ABSTAIN: COUNCIL MEMBERS – None

Susan J. Blackston

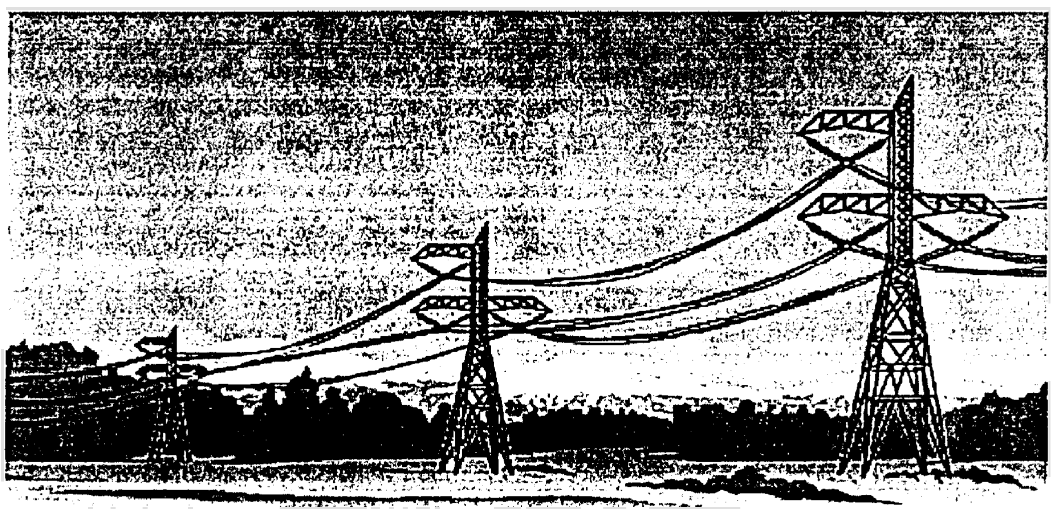
SUSAN J. BLACKSTON
City Clerk

APPENDIX A

7-19-00 E-17

Western
AREA POWER
ADMINISTRATION

Sierra Nevada Regional Office



GREEN BOOK

Post-2004 Power Marketing Plan

Base Resource

July 2000

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INTRODUCTION

This report provides background information and data describing the electrical resources available for the Post-2004-Power Marketing Plan. These resources are referred to as the "Base Resource" and consist primarily of the Central Valley Project (CVP) hydroelectric system. In addition to CVP generation, the existing contract between the Western Area Power Administration (Western) and Enron is considered part of the Base Resource. The report contains data indicating levels of generation that may be expected under various hydrologic conditions and the assumptions upon which the data is based. The report focuses on the CVP's generating facilities and the Project's ability to provide capacity and energy for sale to CVP preference power customers.

Hydrologic conditions are represented as a range from Dry to Wet conditions. Dry hydrologic conditions are represented by a 90% "Exceedence" year. 90% Exceedence refers to the probability that there is a 90% chance that conditions will be as wet or wetter than the year assumed to represent a dry year. Likewise, an average year is represented by a 50% Exceedence year and a Wet Year is represented by a 10% Exceedence year.

CVP generation data used in this report was developed from long-term modeling done for the Central Valley Project Improvement Act Programmatic Environmental Impact Statement (PEIS). The data available in the Green Book is intended to be used as a basis for long-term power resource planning regarding the Base Resource. It does not provide specific operational data for any given year.

PROCESS

The determination of CVP generation was done through a multi-step process. First, the CVP system was simulated to determine the monthly levels of generation that could have been produced over the approximate 70 years of hydrologic data available for the system (Jan. 1922 – Sept. 1991). Data representing the three year types: Dry (90% Exceedence), Average (50% Exceedence), and Wet (10% Exceedence) was then developed from the 70 year record. Next, the monthly generation data was analyzed and adjusted for Project Use, capacity supported with energy and capacity available for operating reserves. In addition, the Green Book includes a theoretical dispatch of the energy available from the Enron contract. **[The CVP Generation combined with the Enron contract data will be appended to the Green Book in September 2000.]**

It is important to keep in mind that this report provides planning level data that will allow for long-term planning of how the Base Resource may be utilized. For shorter term planning (12 months or less), annual estimates of generation will be developed by Western. It is unlikely that these annual estimates will exactly match any of the long-term planning scenarios contained in this report.

This Green Book will be updated as needed. Updates will be prepared when significant changes to the Base Resource occur. Theses changes may be due to changes in CVP operational criteria which impact CVP generation, changes in CVP physical facilities, or changes (or expiration) of the Enron contract.

CENTRAL VALLEY PROJECT DESCRIPTION

THE CENTRAL VALLEY BASIN OF CALIFORNIA

The Central Valley Basin of California extends 500 miles in a northwest-to-southeast direction, with an average width of about 120 miles. It covers approximately one third of the State of California. Except for a single outlet, mountains surround the basin to the west at the Carquinez Strait. The Central Valley floor occupies about one-third of the basin, is about 400 miles in length, and averages 50 miles in width. The Cascade and Sierra Nevada ranges on the north and east rise in elevation to 14,000 ft and the Coast Range on the west to as high as 8,000 ft. Two major river systems exist in the basin: the Sacramento River system in the north and the San Joaquin in the south. The two river systems join at the Sacramento-San Joaquin Delta (the Delta) where the waters commingle before emerging through the Carquinez Strait into San Francisco Bay.

The climate of the Central Valley is characterized as Mediterranean, with long, warm, and dry summers that provide ideal growing conditions for a wide variety of crops under irrigation. The winters are cool and moist. Severe cold weather does not occur, but the temperatures drop below freezing occasionally in virtually all parts of the valley. Rainfall decreases from north to south, with precipitation levels much greater in the mountain ranges surrounding the valley. The average annual rainfall of the Central Valley ranges from about 5 inches in the south to 30 inches in the north. About 80 inches of precipitation, much of it in the form of snow, occurs annually at higher elevations in the northern ranges and about 35 inches occurs in the southern mountains. About 85 percent of the precipitation falls from November through April. Therefore, large variations in snowmelt runoff exist throughout the year, with larger flows occurring during winter and spring and lesser flows during the summer and fall.

SACRAMENTO RIVER BASIN

The Sacramento River Basin includes the west drainage of the Sierra Nevada and Cascade ranges, the easterly drainage of the Coast Range, and the valley floor. The basin covers about 26,500 square miles and extends from north of Lake Shasta to Lakes Folsom and Natoma. Major tributaries to the basin include the Sacramento, Feather, Yuba, and American rivers. Melting Sierra snowpack occurring in early spring and summer generates the greatest volume of runoff. In years of normal runoff, the Sacramento River Basin contributes about 70 percent of the total runoff to the Delta.

SAN JOAQUIN RIVER BASIN

The San Joaquin River Basin encompasses more than 11,000 square miles between the crest of the Sierra Nevada Range and the crest of the Coast Range and stretches to the divide between the San Joaquin and Kings rivers. Major tributaries in the basin are the

San Joaquin, Merced, Tuolumne, and Stanislaus rivers. During normal runoff years, the San Joaquin contributes about 15 percent of the total runoff to the Delta. Water is imported into the San Joaquin River Basin through the Delta-Mendota Canal of the CVP. Major water exports are through the Friant-Kern Canal and the Hetch Hetchy Aqueduct. During the irrigation season and in January and February, much of the San Joaquin River Basin flow is made up of agricultural drainage and local surface runoff.

SACRAMENTO-SAN JOAQUIN DELTA

The Delta covers approximately 1,150 square miles at the junction of the Sacramento (north) and San Joaquin (south) rivers. This area includes about 800 square miles of agricultural lands that derive their water from the Delta. Major tributaries, in addition to the Sacramento and San Joaquin rivers, are the Cosumnes, Mokelumne, and Calaveras rivers. The Delta was originally a vast flat marsh traversed by channels and sloughs. Reclamation began in the 1860s with levee construction. Gradually the Delta was converted to farmland interlaced with dredged channels and levees. Water was directly exported from the Delta first in 1940 with the completion of the Contra Costa Canal (a unit of the CVP). In 1951, water for the Delta-Mendota Canal was pumped from the CVP's Tracy Pumping Plant, and later the Delta Cross Channel Canal was constructed near Walnut Grove to allow a more efficient transfer of water to the Tracy pumps.

Flows in the Delta are affected by a combination of inflows, agricultural uses, diversions, and tides from the Pacific Ocean. When freshwater flows are low, flows often change direction. The distance of upstream movement and saline intrusion varies depending on water quantity. The flows in the Delta and Delta water quality influence U.S. Bureau of Reclamation's (Reclamation) operation of the CVP; however, Sierra Nevada Regions (SNR's) Post-2004 Power Marketing Plan has no effect on the flows to the Delta. Delta outflow is highly seasonal and is characterized by high winter flows from storms and low steady flows in summer from agricultural and reservoir releases.

TRINITY RIVER BASIN

The Trinity River Basin drains approximately 3,000 square miles in northwestern California before flows join with the Klamath River and drain into the Pacific Ocean. The mountainous terrain of the Trinity Basin ranges in elevation from above 9,000 ft to 300 ft at the town of Weitchpec where the Trinity River joins the Klamath River.

The average runoff in the Trinity is approximately 1,200,000 acre-ft at Lewiston and 3,800,000 acre-ft at Weitchpec. The Trinity River Basin exports water at Lewiston Dam to the Sacramento River Basin via the Clear Creek Tunnel.

CVP HYDROPOWER FACILITIES AND OPERATIONAL REQUIREMENTS

The CVP is a large water control and delivery system, initially authorized by Congress in 1935, which covers approximately one-third of the State of California. The water control system consists of storage reservoirs that provide seasonal and annual flow regulation, smaller regulating reservoirs for diversion of water and smoothing of upstream dam and powerplant releases, and canals and pumping plants for the delivery of project water.

The CVP includes 18 constructed dams and reservoirs with a total storage capacity of 13 million acre-ft (MAF). The system includes 615 miles of canals, 165 pumping facilities, 11 powerplants with a maximum operating capability of about 2,085 MW, and approximately 1,120 circuit-miles of high-voltage transmission lines. Reclamation operates all of the powerplants with the exception of the San Luis Unit, which is operated by the State of California Department of Water Resources (DWR), for Reclamation.

Regulating reservoirs situated downstream control water released from the CVP dams. These regulating reservoirs were designed to accept variable levels of water released from the main storage reservoirs and to maintain non-fluctuating flows downstream. In this way, water-level fluctuation is confined to the regulating reservoirs. Power operations do not control the timing or quantities of water released from the regulating reservoirs. CVP hydropower facilities are shown in Table 1. Since this document is expressly meant to define the SNR's Base Resource component of the Post-2004 Power Marketing Plan, the following descriptions will be specific to the CVP hydropower generating facilities.

Table 1 - Power Facilities of the Central Valley Project

Plant Name	Type	Agency	Operating Location	Max. Number of Units	Max. Operating Capability (kW)
Judge F. Carr	Hydro	Reclamation	Clear Creek Tunnel	2	184,000[b]
Folsom	Hydro	Reclamation	American River	3	215,000
Keswick	Hydro	Reclamation	Sacramento River	3	105,000
Nimbus	Hydro	Reclamation	American River	2	17,000
O'Neill	Pump generating	Reclamation	San Luis Creek	6	14,000
W.R. Gianelli	Pump generating	California[a]	San Luis Creek	8	202,000[c]
Shasta	Hydro	Reclamation	Sacramento River	7	625,000[d]
Spring Creek	Hydro	Reclamation	Spring Creek Tunnel	2	200,000[b]
Trinity	Hydro	Reclamation	Trinity River	2	140,000
Lewiston	Hydro	Reclamation	Trinity River	1	350
New Melones	Hydro	Reclamation	Stanislaus River	2	383,000
Total Installed Capacity					**2,085,350**
Total Number of Plants	**11**				

(a) Operated by the DWR for Reclamation.
(b) Limited by tunnel restrictions.
(c) Eight 53,000-kW units for a total installed capacity of 424,000 kW, of which Reclamation's share is 202,000 kW.
(d) With rewinds as of summer 2000

TRINITY RIVER DIVISION

Operation of this division is largely dictated by water rights and environmental constraints related to fisheries, old-mine deposits, suspended solids, and the facilities' physical constraints. Energy production from the Trinity River Division is highly dependent on the amount of diversions to the Sacramento River and releases to the Trinity River. Under normal operating conditions, 1 acre-ft of diversion to the Sacramento River generates approximately 1,100 kWh as water is released through Carr, Spring Creek, and Keswick powerplants. Water released through Lewiston Powerplant generates approximately 48 kWh/acre-ft. Trinity Powerplant generates between 175 and 425 kWh/acre-ft depending on reservoir water surface elevation.

Trinity Lake, Lewiston Reservoir, and Whiskeytown Reservoir are operated to meet target storage levels, flows, and temperature requirements as stipulated in Reclamation's operating policy, based on the agreements of 1960 and 1967 with the California Department of Fish & Game (CDFG) and the National Park Service (NPS), respectively. Operations are being modified by actions implementing the Central Valley Project Improvement Act (CVPIA) and are specific to Kokanee salmon; fall, late-fall, and spring-run Chinook salmon; and steelhead. The CVPIA requires a minimum annual flow rate of 340 thousand acre-ft (TAF) to the Trinity River. In addition to flow regulation, a temperature curtain in Lewiston Reservoir and two temperature curtains in Whiskeytown Reservoir contribute to temperature management for fisheries and influence operations in the Trinity Division. These temperature curtains are designed to provide cool water releases to the Sacramento River over a longer portion of the year than could otherwise be accommodated, thus improving conditions for fish survival.

Operation of Spring Creek Powerplant is at times limited by the need to control the effects of metal concentrations in releases downstream from Keswick Dam. Dilution of toxic mine drainage from Spring Creek Debris Dam is maintained by regulation of diversions from the Trinity Basin via Spring Creek Powerplant and by Shasta outflows. Trinity Lake storage is limited to 2.1 MAF from November 1 through March 31 in accordance with dam safety requirements. Minimum fall carryover storage of 600 TAF in Trinity Lake provides for retention of a 300 TAF pool, which is used to meet water temperature criteria in the Trinity River.

Power production at Carr Powerplant depends on reservoir elevation at Whiskeytown and capacity of Clear Creek Tunnel, which varies depending on frequency of maintenance.

Production at Carr varies with the surface elevation at Whiskeytown Reservoir and ranges from 500 to 600 kWh per acre-ft. Lewiston Lake must be maintained at an elevation above 1,898 ft to avoid developing a vortex at the Clear Creek Tunnel inlet. Like Carr, the capacity of Spring Creek Powerplant is affected by the elevation of Whiskeytown Reservoir, which must be operated at an elevation above 1,100 ft to avoid developing a vortex at Spring Creek Tunnel. Production at Spring Creek Powerplant varies from 425 to 575 kWh per acre-ft depending on reservoir level.

Trinity Dam and Powerplant and Trinity Lake

Located on the Trinity River in northwestern California, Trinity Dam was completed in 1962, creating Trinity Lake with a total storage capacity of 2.4 MAF. Active storage of Trinity Lake is 2.1 MAF. Mean annual inflow from Trinity River to Trinity Lake is 1.2 MAF. Trinity Powerplant located adjacent to the dam, houses two generators with a maximum powerplant operating capability of 140,000 kW. Maximum powerplant release is 3,693 cubic feet per second (cfs).

Lewiston Dam, Powerplant, and Reservoir

Lewiston Dam, completed in 1963, is also located on the Trinity River, 7 miles downstream from Trinity Dam. Lewiston Reservoir functions as a regulating reservoir to control flow fluctuations downstream for Trinity Powerplant and as a forebay to Carr Powerplant. The reservoir also supplies water to the CDFG at Lewiston hatchery. Releases to the Trinity River and diversions to the Sacramento River Basin are controlled at Lewiston Dam. Lewiston Reservoir has a total capacity of 14,660 acre-ft, with 2,890 acre-ft of active storage. Lewiston Powerplant has one unit with a maximum operating capability of 350 kW. When operating at maximum capacity, Lewiston Powerplant releases about 100 cfs.

Judge Francis Carr Powerplant

Carr Powerplant was completed in 1963. The powerplant is located at the outlet of Clear Creek Tunnel, at the northwest extremity of Whiskeytown Reservoir. Water is diverted at Lewiston Dam via Clear Creek Tunnel through Carr Powerplant and into Whiskeytown Reservoir. The powerplant contains two generators with a maximum powerplant operating capability of 184,000 kW. The maximum powerplant release rate is 3,565 cfs.

Whiskeytown Dam and Reservoir

Whiskeytown Dam was completed in 1963. Whiskeytown Dam and reservoir are located 9 miles west of Redding on Clear Creek. The dam and reservoir regulate Trinity River diversions from Clear Creek Tunnel and Carr powerplant and natural inflow from Clear Creek. Mean annual inflow from Clear Creek is 260 TAF. The reservoir has a total storage capacity of 241 TAF and active storage of 213.5 TAF.

Spring Creek Tunnel and Powerplant

Spring Creek Powerplant, located on the Spring Creek arm of Keswick Reservoir, was completed in 1964. Spring Creek Tunnel carries water from Whiskeytown Reservoir to Spring Creek Powerplant and into the Sacramento River above Keswick Dam. The minimum operating elevation in Whiskeytown Reservoir for Spring Creek Tunnel inlet is 1,100 ft. The powerplant houses two generators, with a maximum powerplant operating capability of 200,000 kW. The maximum powerplant release rate is 4,337 cfs.

Spring Creek Debris Dam

Spring Creek Debris Dam was constructed to control sediment and debris and to regulate acid mine drainage from Iron Mountain Mine. Storage capacity behind the earth-filled dam is 5.9 TAF. There are no generation facilities installed at Spring Creek Debris Dam.

SHASTA DIVISION

The Shasta Division is operated to meet flood control objectives, water supply demands along the Sacramento River and in the Bay/Delta, and water quality and minimum flow requirements in the Sacramento River and the Bay/Delta. One acre-ft of water generates 295 to 475 kWh. During the period from October 1 to June 15, Shasta Lake is operated to provide up to a maximum of 1.3 MAF of flood control space.

Keswick Reservoir is operated as a regulating reservoir for upstream powerplants and controls downstream flow fluctuations in the Sacramento River related to power operations. Minimum flows are identified in the Long-term Central Valley Project Operations Criteria and Plan (OCAP) and generally releases are held constant for periods of one week or longer. The operation of Keswick Reservoir and Spring Creek Powerplant is coordinated to prevent scouring of metal sludge deposited from the Iron Mountain Mine in the Spring Creek arm of the reservoir. Operation of Keswick Dam would not change for purposes of electric generation. For Keswick Powerplant, 1 acre-ft of water generates approximately 75 kWh.

State Water Resources Control Board (SWRCB) Water Right Orders 90-5 and 91-01 stipulate daily average Sacramento River water temperature targets at downstream monitoring areas. Shasta Lake is the largest source of water available for improving

Upper Sacramento River water temperatures. Due to reservoir temperature stratification and the location of the powerplant intake structures, releases for temperature control are often made through either the upper- or lower-level outlets in Shasta Dam that bypass the hydroelectric generators.

Shasta Dam, Lake, and Powerplant

Shasta Dam, lake, and powerplant on the Sacramento River were completed in 1945. Shasta Lake has a total storage capacity of 4.5 MAF of which 3.96 MAF is active storage. Shasta Powerplant contains seven generating units, two of which are used for station service. Water is released through five penstocks leading to the generating units, which produce a maximum powerplant operating capability of 625,000 kW beginning summer 2000. The maximum powerplant release is approximately 18,000 cfs. Mean annual inflow to Shasta Lake is 5.2 MAF.

Keswick Dam, Reservoir, and Powerplant

Keswick Dam, completed in 1950, is located approximately 8 miles downstream of Shasta Dam. Keswick is a regulating reservoir for Shasta Lake and Trinity River diversions, controlling flow fluctuations from the upstream dams and powerplants. The reservoir has a total storage capacity of 23 TAF with 7.5 TAF of active storage. Keswick Powerplant, located within the dam, houses three generating units with a maximum operating capability of 105,000 kW. Maximum release through Keswick Powerplant is approximately 16,000 cfs.

AMERICAN RIVER DIVISION

The American River Division is operated to meet flood control, water supply, water quality, fish and wildlife, recreation objectives and to generate power. Water quality criteria stated in several SWRCB decisions and flood control objectives dictate operation of the American River Division. Because of its close proximity to the Bay/Delta (1-day water travel time), Folsom Dam and reservoir are often operated to accommodate quick response to changing water conditions in the Delta. One acre-ft of water generates 270 to 347 kWh.

Lake Natoma is operated as a regulating reservoir for Folsom Powerplant and eliminates downstream fluctuations in the American River. Operation of Lake Natoma provides water for the downstream fish hatchery that was developed to mitigate fishery impacts of project construction.

Folsom Dam, Lake, and Powerplant

Folsom Dam, completed in 1956, is located 30 miles upstream of the mouth of the American River. It was constructed by the U.S. Army Corps of Engineers (Corps) and is operated by Reclamation. Folsom Lake has a total storage capacity of approximately 1 MAF, of which 900 TAF is active storage. Water is released through three penstocks to three generating units, which have a maximum powerplant operating capability of 215,000 kW. Maximum powerplant release is 8,603 cfs. Mean annual inflow to Folsom Lake is 2.7 MAF.

Nimbus Dam and Powerplant and Lake Natoma

Nimbus Dam, completed in 1955, is located on the American River, 7 miles below Folsom Dam. Nimbus Dam backs up Lake Natoma, controlling flow fluctuations from Folsom Powerplant. The dam also serves as a diversion dam for Folsom South Canal. Nimbus Powerplant is housed within the dam and includes two generating units with a maximum powerplant operating capability of 17,000 kW. Maximum powerplant release is 5,100 cfs.

WEST SAN JOAQUIN DIVISION

Water supply demands dictate the operation of the West San Joaquin Division. Overall, these facilities are net users of power. During the winter months, O'Neill and Gianelli (formerly known as San Luis) pumping-generating plants are used to pump water into

San Luis Reservoir for release during the summer months to meet water supply demands and generate power. These plants can be used in the standard pump-storage mode (releasing water for generation during the on-peak period and pumping the water back into the reservoir during the off-peak period).

W.R. Gianelli and O'Neill Pumping Plants

The San Luis Unit, a joint-use project of Reclamation and DWR, is the only facility of the West San Joaquin Division. SNR's scheduling discretion is limited to the O'Neill and W.R. Gianelli pumping-generating plants. O'Neill has a maximum operating capability of 14,000 kW, and the Federal share of W.R. Gianelli is 202,000 kW.

EAST SIDE DIVISION

The East Side Division consists of the New Melones Unit. The division is operated for flood control, water rights, water quality, water supply, seepage problems, and fisheries. During the flood control season, a maximum of 450 TAF of storage space is reserved for flood control.

Operation of the New Melones facilities to meet water quality criteria for the San Joaquin and Stanislaus rivers is dictated by standards set by the SWRCB. These criteria are stated as provisions of the water rights for New Melones; therefore, operation cannot affect the ability to meet *a priori* water right obligations. Compliance with Federal Clean Water Act standards for water quality objectives at Vernalis and in-basin flow objectives in the Stanislaus and San Joaquin rivers contribute to meeting fisheries management objectives in the Bay/Delta. To the extent possible, New Melones is operated within these constraints. The 4-TAF regulation capacity in Tulloch Reservoir allows peaking operations at New Melones generating facility by controlling flow fluctuations downstream. One acre-ft generates 222 to 436 kWh.

New Melones Dam and Powerplant

New Melones Dam, built by the Corps in 1979, is located on the Stanislaus River, 60 miles upstream of the confluence with the San Joaquin River. New Melones Lake has a total storage capacity of 2.4 MAF, of which 2.1 MAF is active storage. New Melones Powerplant consists of two generating units with a maximum operating capability of 383,000 kW. Mean annual inflow to New Melones Lake is approximately 1.1 MAF. Maximum powerplant release is 8,928 cfs.

Tulloch Reservoir

Although not part of the CVP, Tulloch Reservoir, downstream of the New Melones Dam regulates water releases from New Melones Dam. Tulloch Reservoir has a total storage capacity of 68.4 TAF, of which 10 TAF is used for flood control between October and April. About 4 TAF of storage is used for controlling fluctuations in water releases from New Melones. Tulloch Reservoir is owned and operated by the Tri-Dam Project.

WATER SYSTEM MODELING

The CVP system was modeled based on expected water requirements and operating guidelines as assumed in the CVPIA PEIS. The primary long-term planning tool for evaluating the Central Valley Project water operations is PROSIM. In addition, PROSIM is used to calculate ***incidental*** CVP power generation and Project Use resulting from simulated operations. The term "PROSIM" refers to Reclamation's PROjects SImulation Model. The version of the model used for the PEIS and Trinity River Mainstem Fishery Restoration EIS/EIR (Trinity EIS/EIR) is commonly referred to as PROSIM99. All references herein to PROSIM or PROSIM99 should be considered analogous. The purpose of this section is to document the hydrologic modeling that was done using PROSIM for the PEIS and Trinity EIS/EIR, which forms the basis for estimating the Base Resource. In addition to PROSIM, a second reservoir/stream flow operations model, SANJASM (SAN Joaquin Area Simulation Model (SANJASM) was used to simulate operations of the San Joaquin River system. Simulated operations of New Melones Reservoir from SANJASM are then used by PROSIM in estimating overall CVP generation.

PROSIM is a monthly planning model designed to simulate the hydrologic system comprised of the CVP and State Water Project (SWP). This model uses a modified hydrologic sequence that is meant to be representative of future hydrology. Operations of these Projects for the purposes of water supply, flood control, recreation, maintenance of instream flows, water quality, fish and wildlife, hydroelectric power generation, etc. are defined by the user via input data files. The model is intended to be a tool to aid the user in determining impacts of proposed changes to the system.

PROSIM simulates the operation of Trinity Lake, Whiskeytown Lake, Shasta Lake, Lake Oroville, Folsom Lake, San Luis Reservoir, and the southern SWP reservoirs. San Luis is treated as two distinct reservoirs - CVP San Luis and SWP San Luis. The southern

SWP reservoir system including Pyramid, Castaic, Silverwood, Perris lakes is represented by two aggregated storage facilities, East Branch Reservoir and West Branch Reservoir.

The SANJASM model is a monthly time-step surface water accounting model that simulates major surface water hydrologic features in the San Joaquin River Basin, and on rivers tributary to the east side of the Sacramento-San Joaquin Delta. SANJASM simulates reservoir operation and accounts for average monthly reservoir storage levels, stream flows, surface water diversions, return flows, and average water quality conditions. Its primary relationship to estimating CVP power generation is that this model provides a time series for New Melones Reservoir operations that is treated as input for PROSIM. Because PROSIM uses SANJASM output and vice versa, some iteration between PROSIM and SANJASM is required.

In addition to SANJASM, additional primary inputs to PROSIM are outputs from other models. They include:

- Hydrologic data DWR's Consumptive Use (CU) and Depletion Analysis (DA) models)
- Water demands (from the CU/DA models and specific water agencies)

This data was used to develop water demand, reservoir inflow, and local accretion/depletion data for the 2020 level of development used in the PEIS alternatives. For agricultural analysis, this means that acreage and crop mix is based on the 2020 projections and assumptions in DWR Bulletin 160-93. Urban land use and water demand is also included in Bulletin 160-93. Other primary inputs included water use data (from water agencies) and CVP operational criteria as defined by the PEIS alternatives. For the purpose of estimating future CVP power production, the Cumulative Effects Run that was common to both the PEIS and Trinity EIS/EIR was used. Simulated PROSIM reservoir storages and releases are then used to determine the available capacity and energy for the CVP's powerplants.

ASSUMPTIONS USED IN THE PEIS ALTERNATIVE

The PEIS alternatives were developed to evaluate a range of actions, or programs, to meet the objectives of CVPIA and implement provisions of CVPIA. Different actions were added to the PEIS alternatives to represent a matrix of proposed actions. To simulate the power available in the Base Resource, Western used the PEIS's Cumulative Effects Run. It included all assumptions in the PEIS Preferred Alternative plus additional programs and commitments of CVP resources that are possible under future CVP operations.

The following assumptions are included in the Cumulative Effects Run:

- The Bay-Delta Plan Accord as defined in the Draft Water Quality Control Plan
- Coordinated Operations Agreement (COA) with revisions to 1986 sharing formula to model export restrictions per the Draft Water Quality Control (The COA and Public Law 99-546 assume revision of items such as the sharing formula, given a more recent Water Quality Control Plan).
- The 1993 Winter Run Biological Opinion as amended in 1995 by National Marine Fisheries Service (NMFS)
- American River minimum stream flow requirements based on recent operational practices, which attempt to meet some of the requirements of SWRCB Decision 1400 with minimum flow requirements per SWRCB Decision 893
- Renew all CVP service, water rights, and exchange contracts at existing amounts
- Implement water measurement
- Implement (b)(1) program
- Upgrade Tracy and Contra Costa pumping plants fish protection facilities
- Construct Shasta Temperature Control Device
- Complete improvements to Coleman National Fish Hatchery
- Implement Non-Flow Stream Restoration Actions in Central Valley streams

- Complete modifications to Anderson-Cottonwood Irrigation District and Glenn-Colusa Irrigation District diversion facilities for fish protection
- Implement Seasonal Field Flooding
- Increase instream Fish Flow releases in Trinity River based on 360 to 815 acre-ft pattern
- Purchase 30,000 acres of retired land
- Implement Fish and Wildlife actions per Sections 3406(b)(2) and (3) of CVPIA
- Provide Level 2 and Level 4 refuge water supplies with 40/30/30 shortage criteria
- Implement water pricing actions
- Modify Red Bluff Diversion Dam
- Construct Delta Fish Barriers
- Provide for water transfers
- Revegetate retired lands

Other CVP system operations are consistent with the criteria defined in the OCAP. For a detailed description of the Cumulative Effects Run and other PEIS alternatives, please see the Draft and Final PEIS. Key assumptions of CVP system operations are discussed below.

IMPLEMENTATION OF INCREASED INSTREAM FISH FLOW RELEASES IN THE TRINITY RIVER

Changes in the instream fish flow release pattern affects the amount of water that can be exported to the CVP from the Trinity River. Changes in the amount of CVP exports from the Trinity River can significantly affect how the CVP is operated.

In October 1984, the U.S. Fish and Wildlife Service (USFWS) began a 12-year study to describe the effectiveness of increased flows and other habitat restoration activities to restore fishery populations in the Trinity River. The Trinity EIS/EIR was to evaluate alternatives to restore and maintain natural production of anadromous fish in the Trinity

River mainstem downstream of Lewiston Dam. Historically, an average annual quantity of approximately 1.3 million acre feet of water was diverted from the Trinity River to the Sacramento River system (1964-1992). A change in the Trinity River flow requirements and a corresponding change in the amount of water diverted to the Sacramento River system could affect future flows to the Delta. Changes also could affect overall water supply reliability and carryover storage in Shasta Reservoir, water quality and temperature in the Sacramento River, and reduce overall CVP hydropower production. The Cumulative Effects Run assumed the final flow in the Flow Evaluation Study Alternative (which is also the Preferred Alternative in the Trinity River EIS/EIR). The assumed flows range from 362,000 acre-ft/year in critical dry years to 815,000 acre-ft/year in extremely wet years.

Fish and Wildlife Management Programs

The Fish and Wildlife Management Programs included methods to improve habitat, as defined by the Anadromous Fish Restoration Program (AFRP) and refuge water supplies. The program associated with refuge water supplies was defined in a 1989 Refuge Water Supply Study and the San Joaquin Basin Action Plan completed by Reclamation. The AFRP was implemented in the PEIS alternatives through the instream and Delta habitat and flow improvements. The following three tools were identified in the CVPIA to improve flows. (The definitions were developed for the purposes of the PEIS).

- ***Reoperation of the CVP in accordance with Section 3406(b)(1)(B).*** Reoperation is defined as changes in CVP operations that do not impact water deliveries to CVP water users.

- ***Dedication of 800,000 acre-ft of CVP water in accordance with the November 20, 1997 Administrative Paper for Section 3406(b)(2) (or (b)(2) Water).*** The "(b)(2) Water Management" is defined as operation of the CVP in a manner that would allow the CVP to dedicate and manage 800,000 acre-ft/year of CVP water for fish and wildlife purposes, as measured as a reduction in deliveries to CVP water service contractors.

The (b)(2) Water Management cannot adversely impact non-CVP water rights holders (including the SWP), Sacramento River Water Rights Contractors, or San Joaquin River Exchange Contractors. In addition, the (b)(2) Water Management cannot impact the ability of the CVP to meet the winter-run Chinook salmon or delta smelt biological opinion. The (b)(2) Water Management process can reduce deliveries to agricultural and municipal and industrial (M&I) CVP water service contractors as much as 800,000 acre-ft annually.

The (b)(2) Water Management included the following three components.

The "Bay-Delta Plan Component" includes the reduction in CVP water deliveries that occurred due to implementation of the Bay-Delta Plan Accord, as described in the Accord.

The "Instream Component" refers to use of (b)(2) water on the CVP-controlled streams to meet the Draft AFRP target flows. The primary goal of the (b)(2) Water Management Instream Component was to provide water for AFRP salmon and steelhead target flows in the Sacramento, American, Stanislaus and Lower San Joaquin rivers, and in Clear Creek.

The "Delta Component" refers to the use of (b)(2) water in the Delta to meet Draft AFRP target flows and operational considerations in excess of those identified in the Bay-Delta Plan.

- ***Water Acquisitions in accordance with Section 3406(b)(3).*** Water Acquisitions from willing sellers would be used to provide increased instream flows in specific months to improve habitat, in accordance with preliminary information developed by AFRP. Acquisition of up to 140,000 acre-ft per year from willing sellers on the Stanislaus, Tuolumne, Merced, Calaveras, Mokelumne, and Yuba rivers to meet instream and Delta fisheries needs is assumed. Some unquantified purchases on tributaries to the upper Sacramento are also assumed. A portion of the acquired water would be managed for increased flows through the Delta. The remaining portion of the acquired water could be exported.

Water facilities operations were modified to reflect the use of these three tools. Implementation of CVP reoperation and 3406(b)(2) Water Management for upstream and Delta actions are similar to those defined in the November 20, 1997, Administrative Paper released by Reclamation and the USFWS.

COORDINATED OPERATIONS AGREEMENT (COA)

For the PEIS analysis, it is acknowledged that the COA may change in the future, but without knowledge of these potential changes, the COA is assumed to be in place per current agreement. Currently, the COA is assumed to be in place with revisions to 1986 sharing formula to model export restrictions per the Draft Water Quality Control Plan. The 1986 sharing formula was designed for D-1485 conditions and includes D-1485 assumptions for the inflow/export ratio and the spring pulse period. The COA and Public Law 99-546 assume revision of items such as the sharing formula, to implement the most recent Water Quality Control Plan.

Each month, once the reservoirs are operated to meet upstream requirements and the minimum desirable exports are determined, PROSIM simulates the Delta operations. If supply into the Delta exceeds the outflow requirements and export capacities, the Delta is considered to be "out-of-balance" and no sharing formula is applied. In this case, the Projects (CVP and SWP) each export their respective maximum amounts, as export area constraints allow. Under converse conditions, *i.e.*, "in-balance" conditions, two conditions occur. The first condition is when there is no "unstored" water for export. Under this condition, the water supply responsibility is shared CVP 75 percent and SWP 25 percent. The second condition is when there is "unstored" water for export. The water supply entitlement is shared CVP 55 percent and SWP 45 percent. How much additional water each Project releases from upstream reservoirs is a function of how much they are already releasing relative to their respective inflows and how much they are exporting within the framework of the governing sharing percentages.

LIMITATIONS TO PROSIM MODELING

USE OF PROSIM AS A NON-COMPARATIVE MODEL

Traditionally, PROSIM and other long-term water planning models have been used to compare proposed operational scenarios. It is generally assumed that the model will provide accurate incremental differences without necessarily being a good predictor of an "absolute operation". Increasingly, PROSIM and other similar planning models are being used in a prescriptive manner to define absolute operations. Results of the PEIS Cumulative Effects Run are being used to represent specific yearly generation for a given year and not just the difference in generation for that given year. These results are being used to develop a probabilistic distribution, which is then being used in the analysis presented in this document. A concern with this methodology may be unwarranted, but PROSIM generation predictions must be kept in their proper perspective.

SHASTA STORAGES

With the implementation of the CVPIA as modeled in the PEIS, it is not possible to maintain the same minimum storage levels in Shasta Lake as in pre-CVPIA conditions. As an example, during the dry period, the minimum storage in the PEIS Preferred Alternative is reduced to approximately 540,000 acre-ft, which is 460,000 acre-ft less than the minimum storage of 1,000,000 acre-ft maintained in the PEIS No-Action Alternative. This minimum storage is near the historical minimum of about 560,000 acre-ft, which occurred in 1977. While as noted previously, it is important to keep in perspective any "absolute" data derived from PROSIM, it raises concerns that implementation of the CVPIA would result in lower dry period storage conditions. These storage reductions in Shasta Lake reduce the ability of the CVP to maintain the cold water pool for releases to comply with 1995 Winter-Run Biological Opinion temperature requirements and will require re-consultation with NMFS. The biological opinion requires a minimum end-of-water year storage of 1.9 million acre-ft in Shasta Lake to maintain the cold water pool for Sacramento River temperature control, except in the 10 percent driest years. In these extremely dry years, Reclamation would reconsult with NMFS to determine appropriate operations under the biological opinion. Reclamation's temperature model simulations indicate a decrease in the frequency of temperature compliance during summer months. It must be recognized, that due to the limitations of the monthly models used to simulate temperature operations, the models are not able to account for all of the operational variables that affect river temperatures and therefore may under represent temperature impacts.

It may be unrealistic to assume that Shasta storage would be allowed to decrease a large amount below the No-Action condition. This could change the amount of CVP energy and capacity available in a dry period.

SECTION 3406(B)(2) – DEDICATED WATER

The CVPIA directs that, upon its enactment, the Secretary of the Interior dedicate and manage annually 800,000 acre-ft of CVP yield for the primary purpose of implementing the fish, wildlife, and habitat restoration purposes and measures authorized by the CVPIA. In November 1997, Interior adopted an Administrative Paper for accounting and managing water dedicated under (b)(2). This was the basis for the analysis done in the Cumulative Effects Run.

As a result of litigation, the accounting method used to analyze the impact of implementing the November 20, 1997 Administrative Paper has been replaced by a final decision on implementation of (b)(2), which was released on October 5, 1999. In addition to describing the final accounting method, the October 1999 decision sets out a policy for use of the water that differs in some respects from the November 20, 1997 paper. While the November 1997 paper described with particularity the fish measures to be implemented, the October 1999 decision sets forth a range of actions and acknowledges the discretion granted by the statute to the USFWS to manage the (b)(2) water annually. This feature of the October 1999 decision makes it extremely difficult to construct a typical scenario for (b)(2) dedication and management that spans the study period of the PEIS. The October 1999 decision also establishes a comprehensive process for the Department of the Interior to coordinate (b)(2) water management with the CALFED Bay-Delta Program and to engage stakeholders. This adds additional uncertainty to the planning level evaluation of (b)(2) dedication and management. It is likely that amounts of (b)(2) water dedication and management in a specific river reach would vary from year-to-year. No year can be viewed as a typical year, representative of any other year. This makes quantitative analysis almost impossible. A Court Decision in March 2000 substantially upheld Interior's final b(2) proposal.

At this time, there has been no long-term analysis of the final b (2) proposal. It is likely that this final proposal will result in some seasonal shifts of generation and Project Use from the Cumulative Effects Run.

Calfed Programmatic EIS/EIR

The CalFed Bay-Delta Program (CalFed Program) is a cooperative effort of 15 State and Federal agencies with regulatory and management responsibilities in the San Francisco Bay/San Joaquin River Bay-Delta (Bay-Delta) to develop a long-term plan to restore ecosystem health and improve water management for beneficial users of the Bay-Delta system. The objective of this collaborative planning process is to identify comprehensive solutions to the problems of ecosystem quality, water supply reliability, water quality, and Delta levee and channel integrity. Implementation of the long-term CalFed Program will follow the approval of a final CalFed Programmatic EIS/EIR and subsequent environmental review for project-specific aspects of the CalFed Program. Alternatives presented in the Draft CalFed Programmatic EIS/EIR demonstrated a wide range of impacts to CVP power generation.

PROJECT USE RESULTING FROM JOINT POINT

Joint Point is essentially the pumping of CVP water at the SWP's Banks Pumping Plant. This is increasingly being looked at as a "tool" to mitigate impacts to CVP Water Contractors from CVPIA actions and possibly CalFed implementation. Since much of this pumping is done on-peak (and can also result in on-peak pumping at Gianelli), potential impacts of these actions include reduces capacity available to CVP preference power customers. An example of this occurred in March 2000 when Project use for the month hit a peak of 600 MW.

POWER SYSTEM MODELING

Reclamation's PROSIM model was utilized to operate the water system in a manner that approximates how the system *would have been operated* over the 70 years of hydrologic history had the above noted water requirements and operating guidelines been in place. As noted, the results of this modeling provide a *monthly* record of generating capacity at each CVP hydroelectric generator, the amount of energy produced during the month at the plant and the amount of Project Use consumed.

HYDROLOGIC WATER YEARS

The results from modeling 70 years of water system operations provides a great range of capacity and energy available for sale. In order to make this data usable for marketing and electric system planning purposes, it is necessary to first identify the type of hydrologic conditions that are being represented (i.e. wet, average, or dry etc.). For purposes of this report, three types of hydrologic conditions were identified: Dry, Average, and Wet (90%, 50%, and 10% Exceedence Years. In addition to presenting capacity and energy data for the various hydrologic conditions noted, similar data is presented representing the maximum and minimum monthly extremes that may be realized.

Generation available under Dry and Wet conditions was identified based on the establishment of a contiguous 12-month period (i.e. rolling 12-month). This process involved the construction of 826 consecutive 12-month periods over the course of the 70 years of modeling. This record of consecutive 12-month periods was then sorted in descending order based on the gross energy (i.e. energy generated by the CVP prior to deducting energy required for Project Use) generated by the CVP. The period representing Wet hydrologic conditions was defined as the 12 consecutive months (August 1981 – July 1992) in which the gross energy generated by the CVP was exceeded only 10% of the time (10% Exceedence). The period representing Dry hydrologic conditions was defined as the 12 consecutive months (September 1929 – August 1930) in which the gross energy generated by the CVP was exceeded at least 90% of the time (90% Exceedence). See the attached information relating to reading Exceedence curves.

Generation produced during each month of an Average year was calculated using a simple arithmetic averaging over the 70-year record for each month.

In addition to the Wet and Dry years developed based on the exceedence criteria, this report also presents data for Maximum and Minimum synthetic years. These synthetic years consists of data indicating the maximum and minimum level of generation for each month contained in the 70 years of PROSIM output. The months were chosen based on CVP gross energy generated. The data is presented primarily to indicate the range of generation that may be expected in any month.

PROSYM

For each of the three water year types identified (Wet, Dry & Average), the monthly generation was modeled utilizing the PROSYM production cost model. The PROSYM model is an electric production cost model, which performs economic dispatch of an electric system to optimize the use of the generation resources in meeting a given load curve. For the purposes of this study, a historic hourly load curve for CVP preference power customers was utilized.

PROSYM is a simulation program that models chronological electric production and is designed to be used for electric utility operating and planning studies. The program is designed to provide detailed hour-by-hour investigation of the operations of electric generating resources. This hour-by-hour investigation enables the simulation to closely reflect actual electric utility operation and is especially useful in studying operations at hydroelectric facilities. The program provides for upstream generation and water to be dispatched in a peaking mode; using regulating reservoirs to regulate downstream flows, thus maintaining prescribed river flows.

The PROSYM program is designed to generally dispatch hydroelectric units before any other resource type is used (e.g., fossil fuel, nuclear, etc.). This is done in recognition of hydropower's very low operating costs, limited energy supply, and the way its peaking ability is generally valued and utilized within the electric utility industry. This is accomplished through coordinated operation of the hydroelectric powerplants to levelize the residual hourly load shape that thermal and purchased resources would serve. This type of operation serves to maximize the value of the hydro resources and tends to minimize the need for additional capacity acquisition or construction. In addition, work is currently underway to dispatch the CVP generation based on its market value. **[The results will be appended to this report in September 2000.]**

A hydroelectric powerplant's minimum capacity will normally be controlled by the minimum water flow required though the powerplant. For generating units with regulating reservoirs, the size of the regulating reservoir is also modeled. In addition, the amount of water in the regulating reservoir at the beginning of each week can be specified. Given these constraints, the model will then utilize upstream hydroelectric generation to maximize its capacity in meeting load to the extent there is storage available in the regulating reservoir and downstream releases can be maintained at their specified levels.

In addition, hourly data is required to determine the actual load-carrying capability of the hydro system. The monthly capacity, as reported by the PROSIM model, is a "head dependent" capacity based on the average amount of storage in each reservoir for a month. In the determination of the load-carrying capability of the system, the "head-dependent" capacity represents a maximum level of *instantaneous* output. However, the amount of energy generated at each powerplant (i.e., the amount of water released through each powerplant) must also be taken into account, as well as the shape of the load curve into which the hydro resource is dispatched and certain flow constraints and downstream regulation requirements. The load-carrying capability is the maximum level of *sustainable* energy production within a given load shape that results in minimizing the acquisition of additional capacity. Load-carrying capability may also be referred to as *capacity supported with energy*.

Power System Modeling

In order to assist in planning, generation duration curves were developed to illustrate the levels of CVP generation being dispatched in PROSYM for each hour. The data presented notes the net energy being dispatched for use in the CVP preference power customer load curve. Of particular note are the levels of negative capacity during certain months. The curve represents the total generation dispatched each hour to meet both

CVP preference customer load and Project Use loads, less the Project Use in each hour. Thus, if little generation is dispatched in a given hour (generally an off-peak hour); the curve most likely will be negative since the Project Use load is subtracted in order to indicate the net available for CVP preference customer use. There is an assumption that Western will purchase to meet Project Use load during these periods, and the CVP energy that may have otherwise been used to meet the Project Use load will have been used to meet preference customer load during times where it is of higher value (generally on-peak).

MONTHLY DATA

The following monthly data is presented in the attached tables (Tables 1 thru 3) and graphs (Figures 1-12 thru Figures 12-12) for the Average, Dry & Wet years and is defined below.

- Gross Energy (GWh)
- Project Use Energy (GWh)
- Net Energy (GWh)
- Generating Capability (MW)
- Capacity Supported With Gross Energy (MW)
- Coincident Project Use Capacity Requirement (MW)
- Capacity Available For Sale To CVP Preference Customers (MW)
- Capacity Available For Use As Operating Reserves (MW)
- Monthly Generation Duration Curves (MW)
- Average Weekday Generation Profile For Each Month of a Dry, Wet, and Average Year (MW)
- Average Weekend Generation Profile For Each Month of a Dry, Wet, and Average Year (MW)

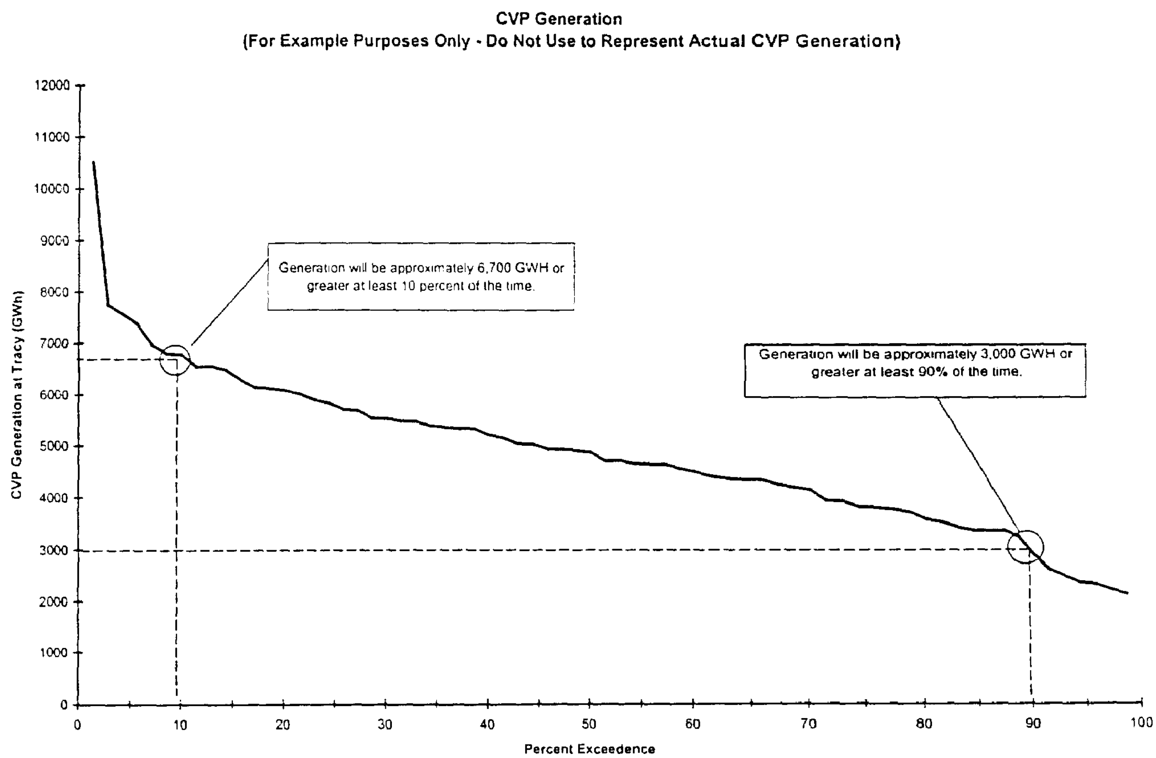
- Peak Weekday Generation Profile For Each Month of a Dry, Wet, and Average Year (MW)

In addition to the data noted above for the Wet, Average & Dry years, monthly maximum and minimum data for the following quantities is also provided in the Tables 4 & 5.

- Maximum/Minimum Gross Energy (GWh)
- Maximum/Minimum Project Use Energy (GWh)
- Maximum/Minimum Net Energy (GWh)
- Maximum/Minimum Generating Capability (MW)
- Maximum/Minimum On-Peak Project Use (MW)
- Maximum/Minimum Generating Capability Available For Sale To CVP Customers And For Operating Reserves (MW)

How To Read An Exceedence Curve

Much of the information included in this document is included in the form of "Exceedence Levels". The figure below is an explanation of how to interpret this type of information. Simply put, if a specific quantity is provided as a 90% Exceedence value, it is likely that the quantity will be at least that great or greater 90% of the time.



Acronyms

AFRP – Anadromous Fish Restoration Program

CDFG – California Department of Fish & Game

COA – Coordinated Operations Agreement

cfs – cubic feet per second

CVP – Central Valley Project

CVPIA – Central Valley Project Improvement Act

DWR – California Department of Water Resources

MAF – million acre-ft

NMFS – National Marine Fisheries Service

NPS – National Park Service

OCAP – Operations Criteria and Plan

PEIS – Programmatic Environmental Impact Statement

PROSIM – PROject SImulation Model

PROSYM – Cost Production Model used to value CVP Generation

SANJASM – San Joaquin Area Simulation Model

SNR – Sierra Nevada Region

SWP – State Water Project

SWRCB – State Water Resources Control Board

TAF – thousand acre-ft

Trinity EIS/EIR – Trinity River Mainstem Fishery Restoration EIS/EIR

USFWS – U.S. Fish and Wildlife Service

DEFINITION OF TERMS

Gross Energy: The total energy produced by the CVP during the period noted.

Project Use Energy: The amount of energy, including station service, required to deliver project water to CVP water customers and for fish and wildlife needs. Project Use accounts for approximately 20 to 30 percent of annual gross energy generation of the CVP.

Net Energy: The difference between Gross Energy and Project Use requirements. Generally this is the amount of energy available for sale to CVP Preference customers.

Generating Capability: The maximum rate of energy production, based on reservoir elevation. This value is the "head-dependent" capacity available at a generation site and is calculated in PROSIM based on the average reservoir elevation for each month.

Capacity Supported With Gross Energy: The maximum level of *sustainable* energy production within a given load shape and over a specific period (i.e. generally a month) that results in minimizing the acquisition of additional capacity and maximizing the value of the CVP generation. The load shape used for the dispatch was a combination of customer and Project Use loads.

Coincident Project Use Capacity Requirement: The level of energy production for Project Use loads that is coincident with the maximum rate of energy production for the combined customer and Project Use loads.

Capacity Available For Sale: The difference between the Capacity Supported With Energy and the Coincident Project Use Capacity Requirement. This is the capacity available for Western to utilize in meeting customer energy requirements.

Capacity Available For Use As Operating Reserves: The difference between the Generating Capability and the Capacity Supported With Energy. This capacity is available to be loaded for relatively short periods assuming that regulating reservoir storage space is available. It is assumed that to the extent the capacity is loaded and water releases are made, the associated energy is no longer available for sale to customers.

Enron Contract: 50 MW resource that is available 16 h ours during each weekday.

Maximum/Minimum Gross Energy: The maximum or minimum level of gross CVP energy produced for the month indicated as calculated by PROSIM.

Maximum/Minimum Project Use Energy: The maximum or minimum level of Project Use energy for the indicated month as calculated by PROSIM.

Maximum/Minimum Net Energy: The difference between the gross energy generated and Project Use energy. This is the maximum and minimum monthly level of generation available for sale to Western customers.

Maximum/Minimum Generating Capability: The maximum rate of energy production based on reservoir elevation. The minimum value represents the maximum rate of energy production during the most adverse hydrologic conditions, while the maximum value represents the maximum rate of energy production during the most favorable hydrologic conditions. This value is the "head-dependent" capacity available at a generation site and is calculated in PROSIM based on the average reservoir elevation for each month.

Maximum/Minimum On-Peak Project Use: The amount of on peak capacity required to operate various CVP features such as pumps during the most favorable and least favorable hydrologic conditions. The value is an estimate of the maximum hourly requirement for the month during the on-peak period.

Maximum/Minimum Generating Capability Available To Customers And For Operating Reserves: The difference between the Maximum/Minimum Generating Capability and the Maximum/Minimum On-Peak Project Use. This is an estimate of the capacity available to customers and for reserves during the most favorable and least favorable hydrologic conditions.

Peak Weekday Generation Profile: The hourly CVP generation that was dispatched on the peak day of each month. This approximates the level of CVP capacity and energy that may be available to meet CVP preference customer load under similar peak conditions.

Average Weekday Generation Profile: The hourly CVP generation that was dispatched on an average weekday of a month. This approximates the level of CVP capacity and energy that may be available to meet CVP preference customer load under similar weekday conditions.

Average Weekend Generation Profile: The hourly CVP generation that was dispatched on an average weekend of a month. This approximates the level of CVP capacity and energy that may be available to meet CVP preference customer load under similar weekend conditions.

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TABLES AND FIGURES

Tables 1 thru 5 Summary of CVP Capacity and Energy

Figures1-1 thru 3-12 Monthly Generation Duration Curves

Figures 4-12 thru 12-12 Daily Generation Profiles

Western Area Power Administration

CVP Capacity and Energy

Tables 1 thru 5

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CVP Capacity and Energy

Table 1
Long Term Average

Month	Gross Energy (GWh)	Project Use Energy (GWh)	Net Energy (GWh)	Generating Capability (MW)	Capacity Supported with Gross Energy (MW)	Coincident Project Use Capacity (MW)	Capacity Available for Sale (MW)	Capacity Available for Operating Reserves (MW)
Jan	329.2	147.9	181.3	1,596.5	969.1	62.0	907.1	689.4
Feb	316.4	123.1	193.3	1,653.3	1,074.6	128.0	946.6	706.7
Mar	341.7	114.5	227.2	1,697.1	777.8	60.0	717.8	979.3
Apr	372.6	60.6	312.0	1,714.5	1,029.9	74.0	955.9	758.6
May	559.3	63.8	495.4	1,714.8	1,447.4	50.0	1,397.4	317.4
Jun	593.9	92.1	501.7	1,701.6	1,448.7	33.0	1,415.7	285.9
Jul	673.1	105.9	567.2	1,665.2	1,592.8	128.0	1,464.8	200.4
Aug	543.6	106.2	437.4	1,589.7	1,507.2	68.0	1,439.2	150.5
Sep	293.2	97.6	195.7	1,501.3	1,228.9	95.0	1,133.9	367.4
Oct	228.2	92.2	135.9	1,483.6	761.5	85.0	676.5	807.1
Nov	206.6	107.0	99.6	1,488.5	695.3	73.0	622.3	866.2
Dec	277.1	127.9	149.2	1,531.6	859.4	149.0	710.4	821.2
Annual	**4,734.8**	**1,238.9**	**3,495.9**	**1,714.8**	**1,592.8**	**149.0**	**1,464.8**	**979.3**

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CVP Capacity and Energy
Table 2
Rolling 12 mos. 90% Exceedance (Dry Year)

Month	Gross Energy (GWh)	Project Use Energy (GWh)	Net Energy (GWh)	Generating Capability (MW)	Capacity Supported with Gross Energy (MW)	Coincident Project Use Capacity (MW)	Capacity Available for Sale (MW)	Capacity Available for Operating Reserves (MW)
Jan	143.4	140.8	2.6	1,471.0	670.2	206.0	464.2	1,006.8
Feb	134.3	129.8	4.5	1,523.0	523.6	120.0	403.6	1,119.4
Mar	171.5	142.2	29.3	1,597.0	529.3	145.0	384.3	1,212.7
Apr	217.0	33.3	183.7	1,640.0	695.1	29.0	666.1	973.9
May	347.0	46.0	301.0	1,631.0	1,078.1	31.0	1,047.1	583.9
Jun	514.9	22.3	492.6	1,612.0	1,383.7	39.0	1,344.7	267.3
Jul	440.9	20.1	420.8	1,548.0	1,224.5	1.0	1,223.5	324.5
Aug	358.4	34.5	323.9	1,465.0	986.2	23.0	963.2	501.8
Sep	198.5	47.3	151.2	1,369.0	892.5	45.0	847.5	521.5
Oct	144.7	27.4	117.3	1,335.0	597.4	22.0	575.4	759.6
Nov	117.2	19.5	97.7	1,319.0	529.2	-	529.2	789.8
Dec	118.8	131.8	(13.0)	1,381.0	539.7	149.0	390.7	990.3
Annual	**2,906.6**	**795.0**	**2,111.6**	**1,640.0**	**1,383.7**	**206.0**	**1,344.7**	**1,212.7**

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CVP Capacity and Energy

Table 3

Rolling 12 mos. 10% Exceedance (Wet Year)

Month	Gross Energy (GWh)	Project Use Energy (GWh)	Net Energy (GWh)	Generating Capability (MW)	Capacity Supported with Gross Energy (MW)	Coincident Project Use Capacity (MW)	Capacity Available for Sale (MW)	Capacity Available for Operating Reserves (MW)
Jan	440.2	156.2	284.0	1,704.0	1,189.1	70.0	1,119.1	584.9
Feb	724.4	157.5	566.9	1,826.0	1,402.4	154.0	1,248.4	577.6
Mar	702.7	105.2	597.5	1,854.0	1,309.8	42.0	1,267.8	586.2
Apr	803.5	87.5	716.0	1,894.0	1,447.1	54.0	1,393.1	500.9
May	566.1	101.1	465.0	1,825.0	1,342.1	79.0	1,263.1	561.9
Jun	551.0	154.8	396.2	1,829.0	1,464.1	182.0	1,282.1	546.9
Jul	803.9	157.2	646.7	1,836.0	1,684.9	117.0	1,567.9	268.1
Aug	531.6	71.7	459.9	1,562.0	1,431.0	92.0	1,339.0	223.0
Sep	237.1	85.7	151.4	1,503.0	1,009.7	122.0	887.7	615.3
Oct	186.0	105.0	81.0	1,493.0	713.3	123.0	590.3	902.7
Nov	323.4	117.8	205.6	1,588.0	820.9	136.0	684.9	903.1
Dec	668.1	140.9	527.2	1,699.0	1,057.1	134.0	923.1	775.9
Annual	**6,538.0**	**1,440.6**	**5,097.4**	**1,894.0**	**14,871.5**	**1,305.0**	**13,566.5**	**7,046.5**

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CVP Capacity and Energy

Table 4
Synthetic Maximum

Month	Gross Energy (GWh)	Project Use Energy (GWh)	Net Energy (GWh)	Generating Capability (MW)	Project Use On-Peak Capacity (MW)	Generating Capability Available to Customer (MW)
Jan 1970	1,089.6	168.5	921.1	1,836.0	230.0	1,606.0
Feb 1983	964.4	131.5	832.9	1,856.0	155.0	1,701.0
Mar 1983	1,123.5	90.2	1,033.3	1,866.0	134.0	1,732.0
Apr 1982	803.5	87.5	716.0	1,894.0	137.0	1,757.0
May 1983	894.5	100.2	794.3	1,878.0	169.0	1,709.0
Jun 1983	967.0	146.0	821.0	1,889.0	209.0	1,680.0
Jul 1983	1,001.5	162.5	839.0	1,875.0	223.0	1,652.0
Aug 1983	827.0	145.5	681.5	1,852.0	206.0	1,646.0
Sep 1983	720.9	144.4	576.5	1,828.0	164.0	1,664.0
Oct 1983	483.1	149.8	333.3	1,779.0	210.0	1,569.0
Nov 1983	777.4	167.8	609.6	1,824.0	256.0	1,568.0
Dec 1983	1,078.3	100.2	978.1	1,828.0	123.0	1,705.0
Annual	**10,730.7**	**1,594.1**	**9,136.6**	**1,894.0**	**256.0**	**1,757.0**

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WESTERN AREA POWER ADMINISTRATION
Green Book

CVP Capacity and Energy
Table 5
Synthetic Mimimum

Month	Gross Energy (GWh)	Project Use Energy (GWh)	Net Energy (GWh)	Generating Capability (MW)	Project Use On-Peak Capacity (MW)	Generating Capability Available to Customers (MW)
Jan 1933	48.3	137.5	(89.2)	874.0	208.0	666.0
Feb 1933	39.0	101.6	(62.6)	884.0	118.0	766.0
Mar 1991	103.5	124.6	(21.1)	1,187.0	203.0	984.0
Apr 1991	143.0	40.0	103.0	1,348.0	86.0	1,262.0
May 1977	214.7	32.0	182.7	1,358.0	68.0	1,290.0
Jun 1991	327.3	40.5	286.8	1,358.0	89.0	1,269.0
Jul 1991	257.8	19.2	238.6	1,282.0	39.0	1,243.0
Aug 1977	200.1	37.5	162.6	1,111.0	70.0	1,041.0
Sep 1931	70.8	58.2	12.6	816.0	105.0	711.0
Oct 1934	61.6	11.8	49.8	784.0	48.0	736.0
Nov 1931	37.8	19.9	17.9	787.0	64.0	723.0
Dec 1931	34.9	135.5	(100.6)	833.0	225.0	608.0
Annual	**1,538.8**	**758.3**	**780.5**	**1,358.0**	**225.0**	**1,290.0**

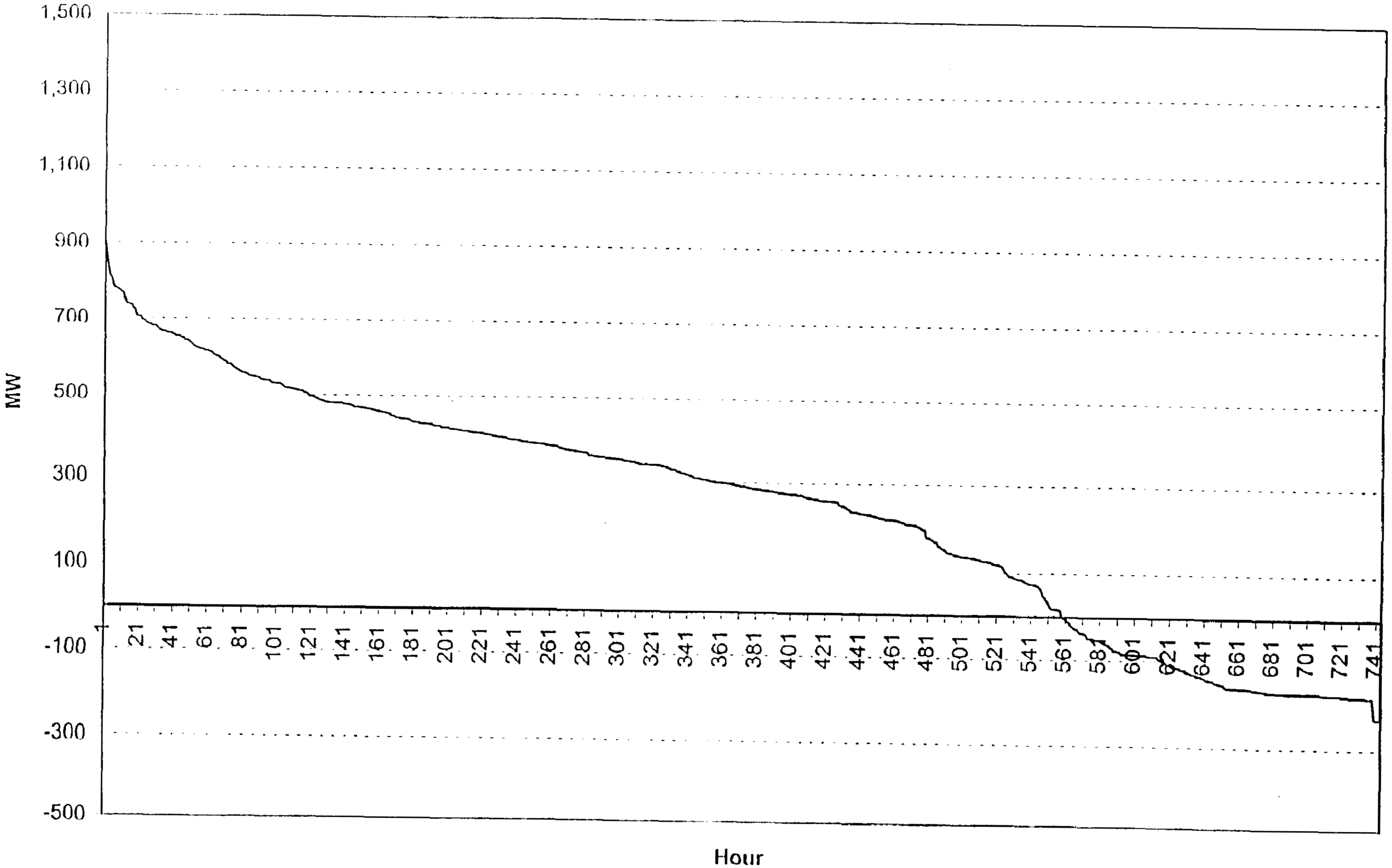
Monthly Generation Duration Curves

Average Generation

Figures 1-1 thru 1-12

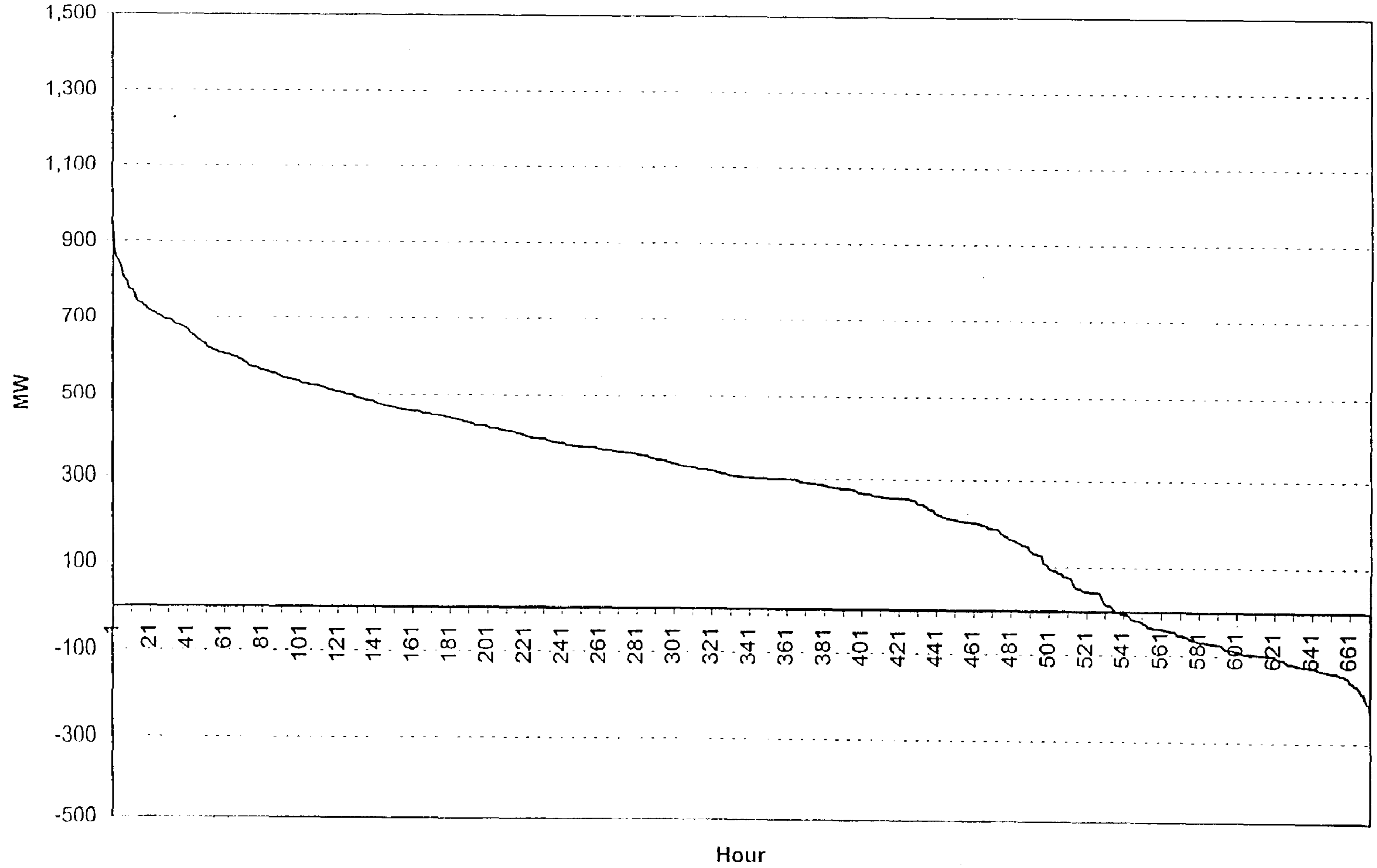
Western Area Power Administration
Green Book
Fig. 1-1

January
Long Term Average Generation



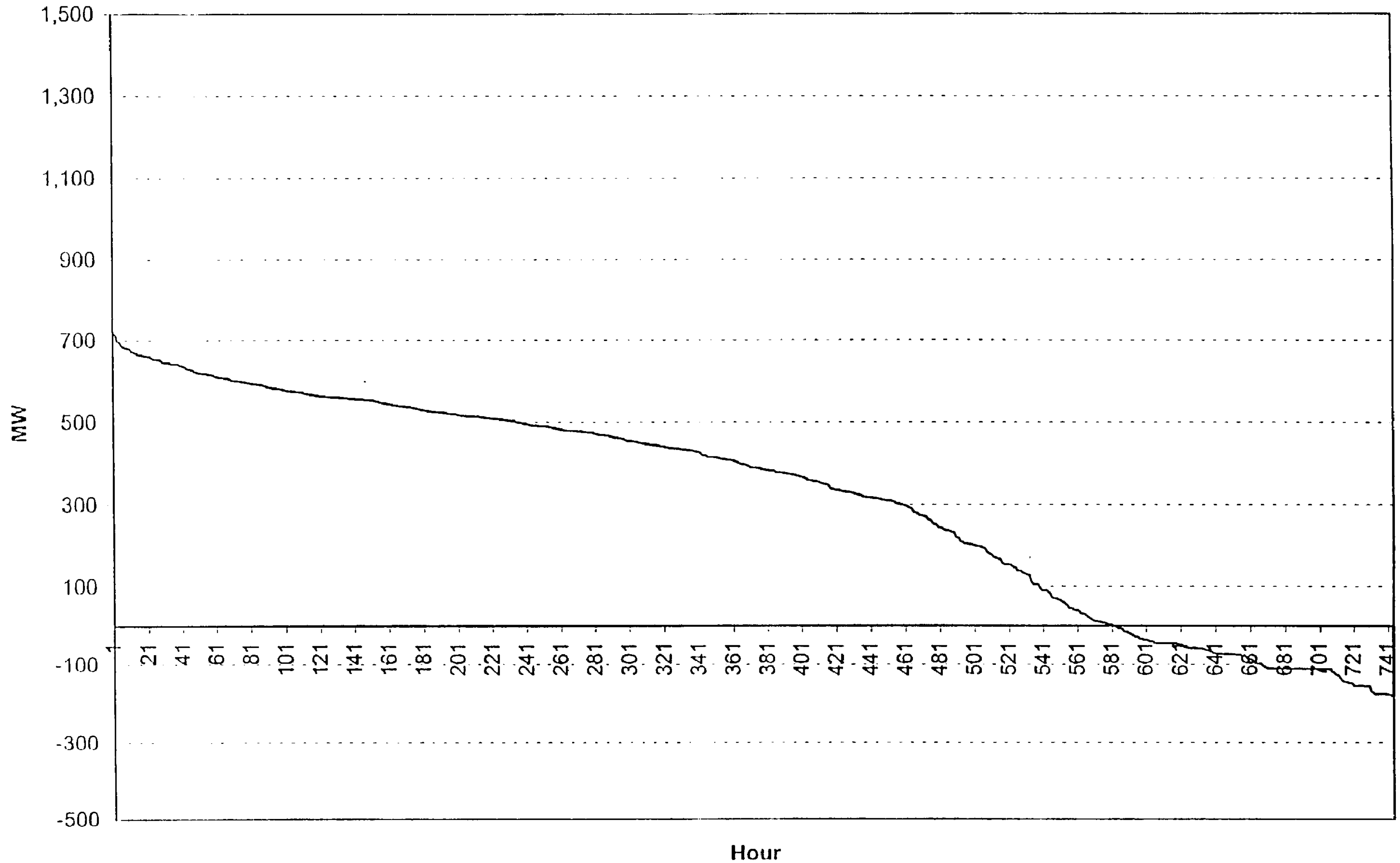
Western Area Power Administration
Green Book
Fig. 1-2

February
Long Term Average Generation



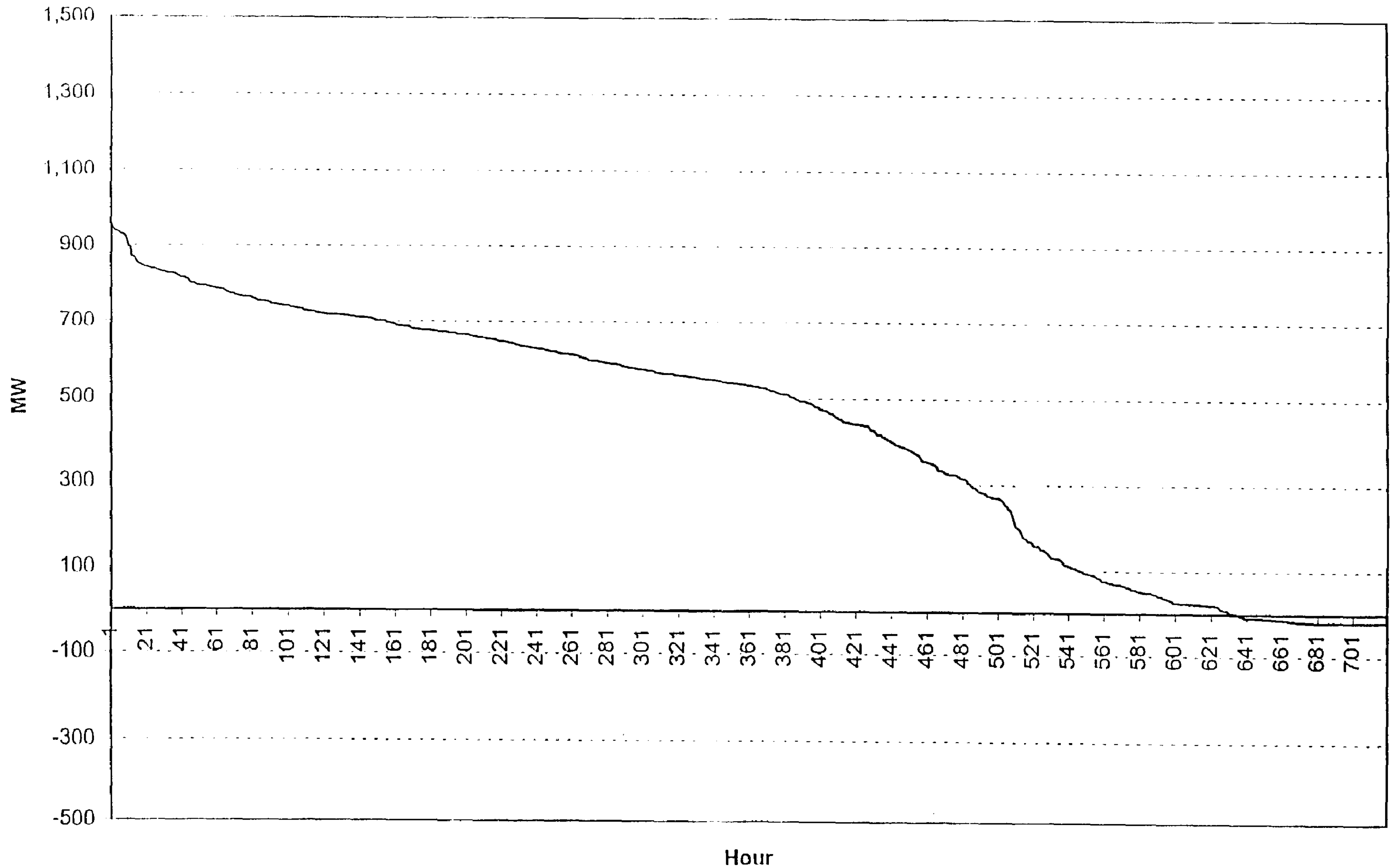
Western Area Power Administration
Green Book
Fig. 1-3

March
Long Term Average Generation



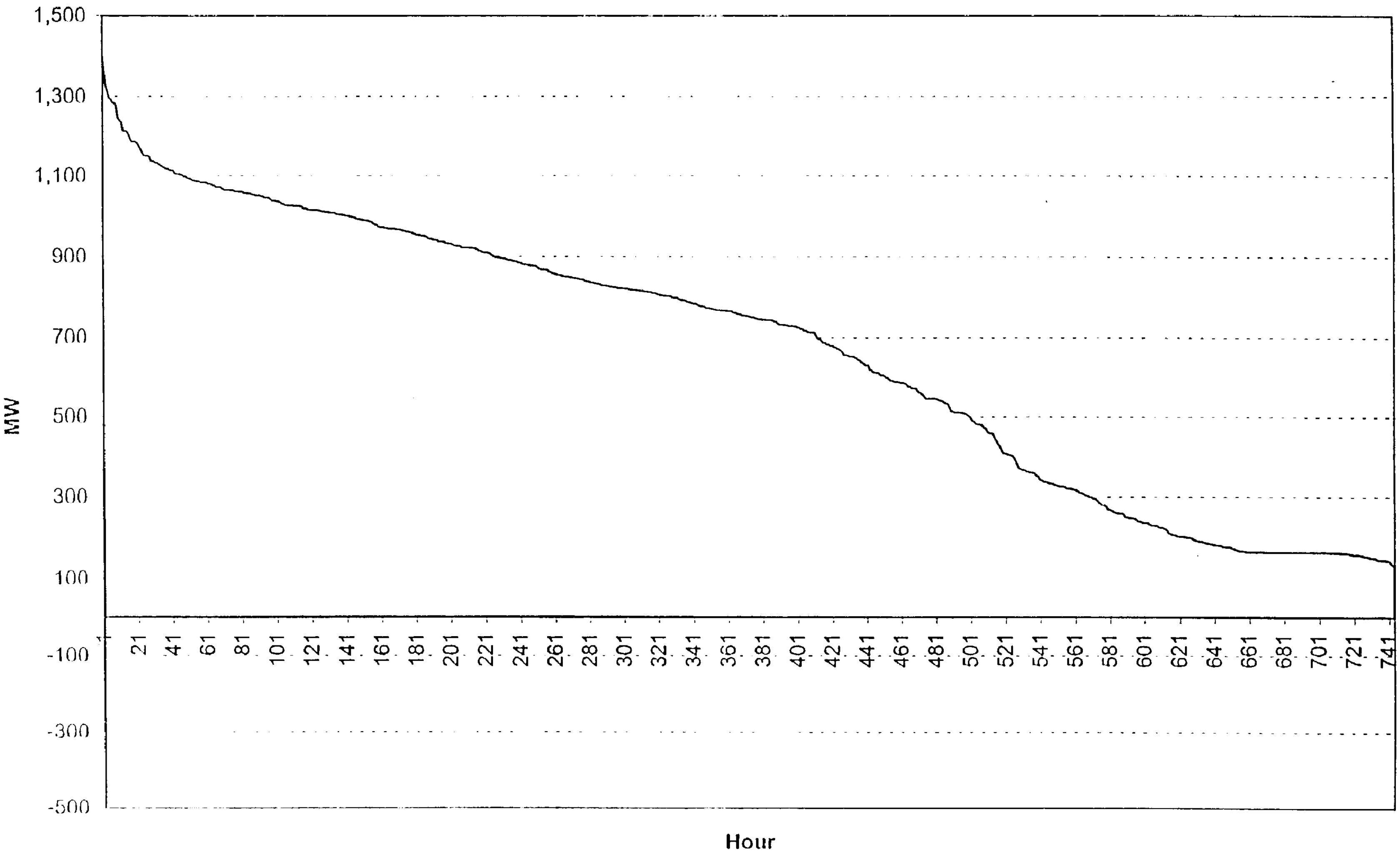
Western Area Power Administration
Green Book
Fig. 1-4

April
Long Term Average Generation



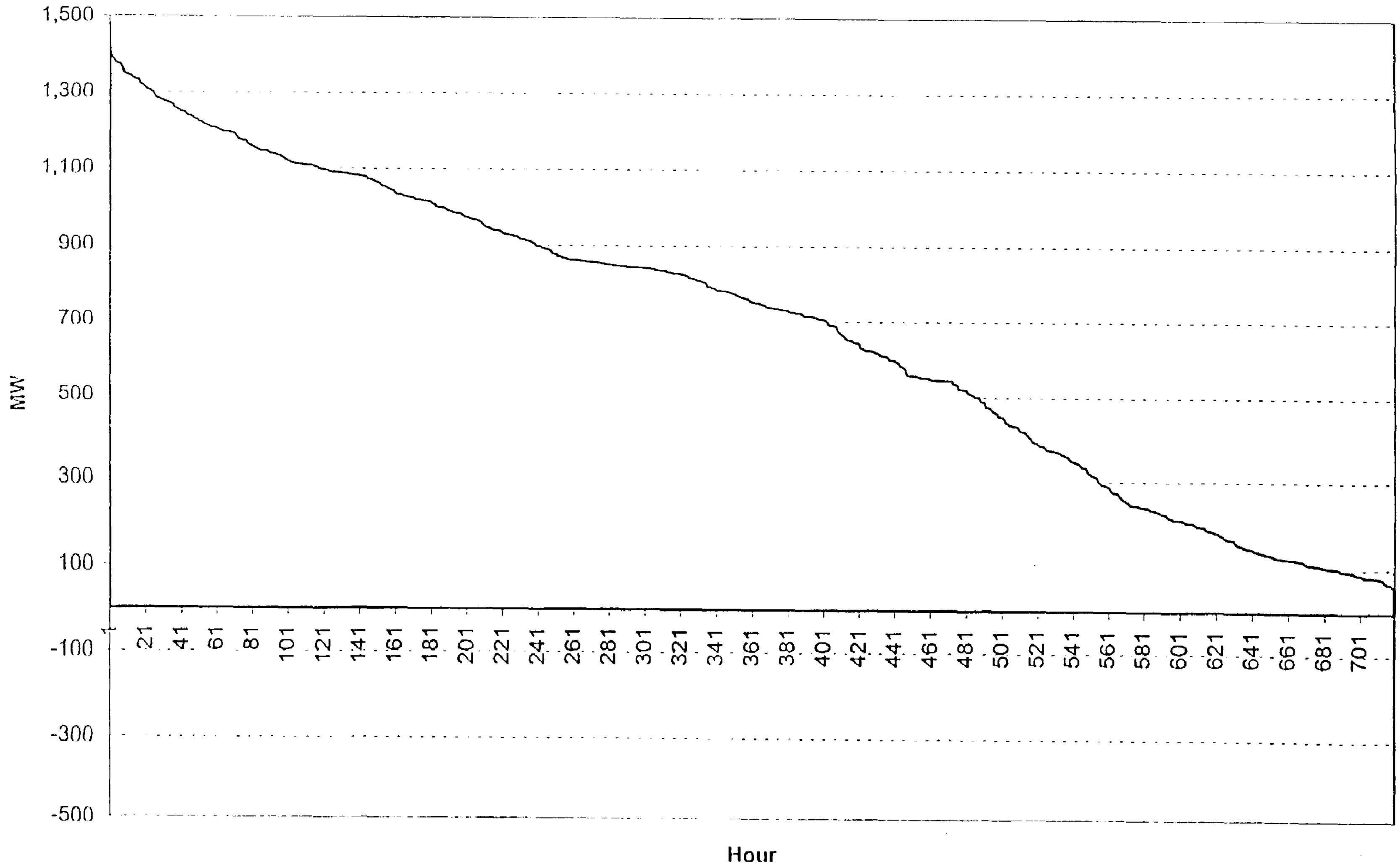
Western Area Power Administration
Green Book
Fig. 1-5

May
Long Term Average Generation



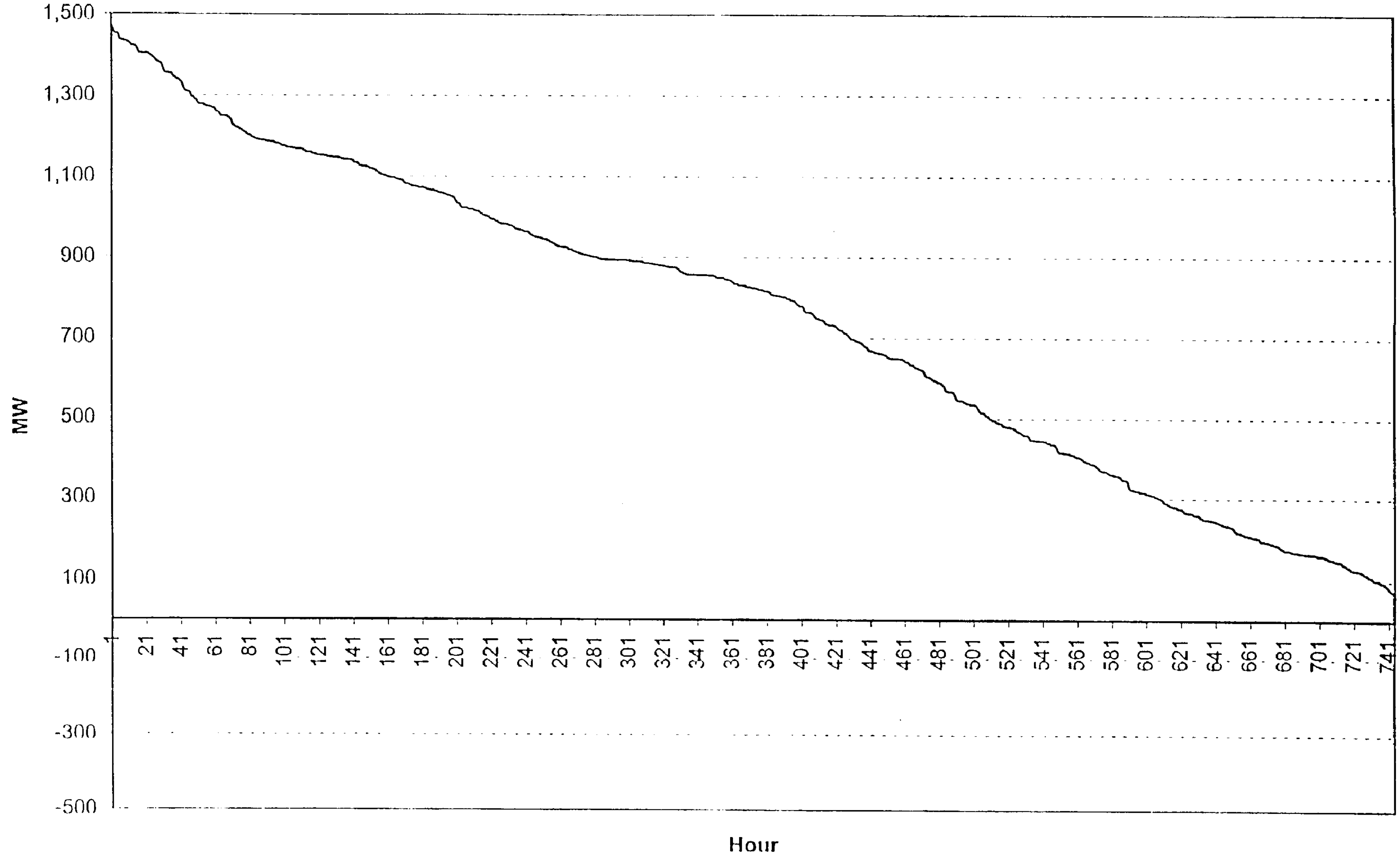
Westen Area Power Administration
Green Book
Fig. 1-6

June
Long Term Average Generation



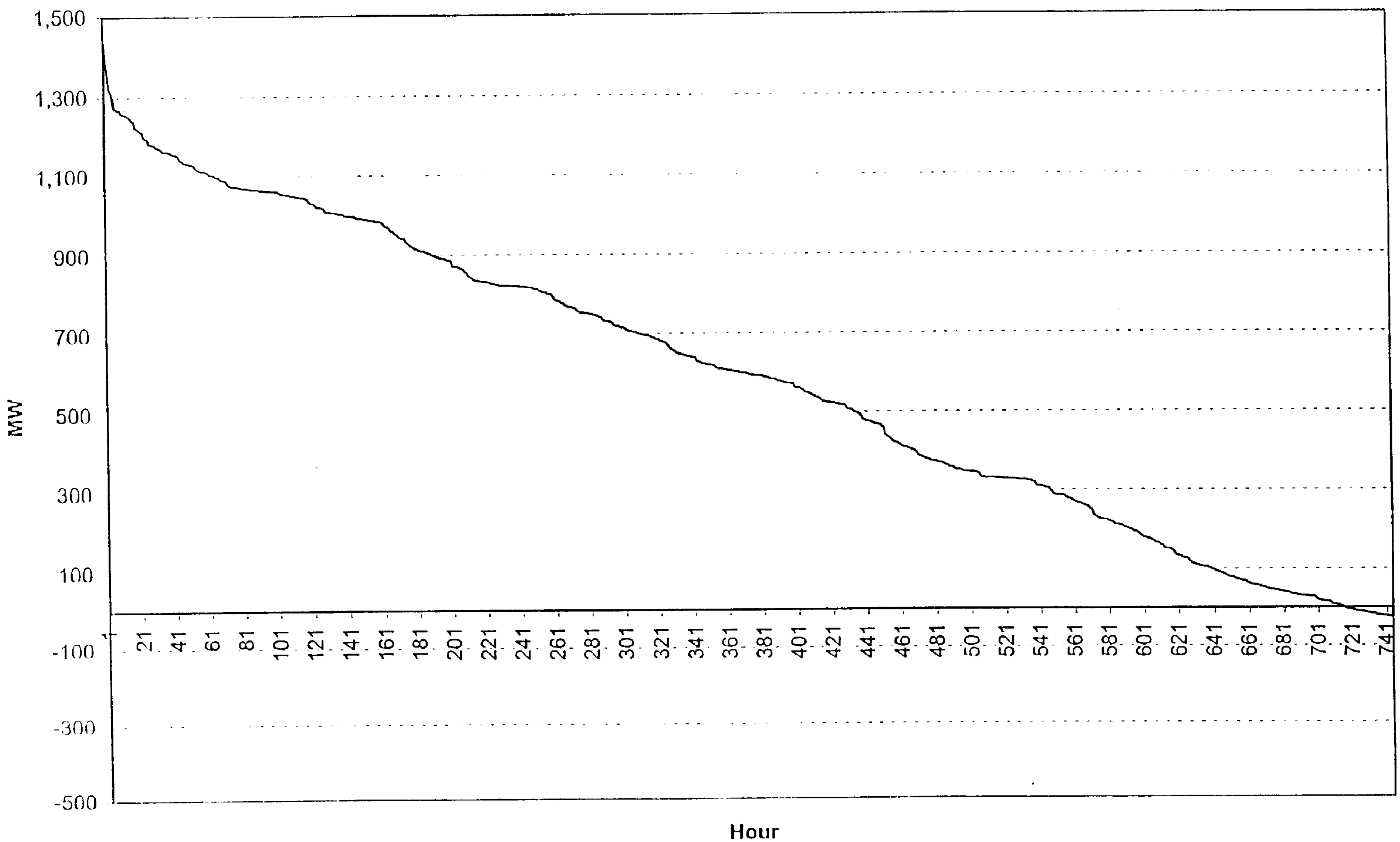
Western Area Power Administration
Green Book
Fig. 1-7

July
Long Term Average Generation



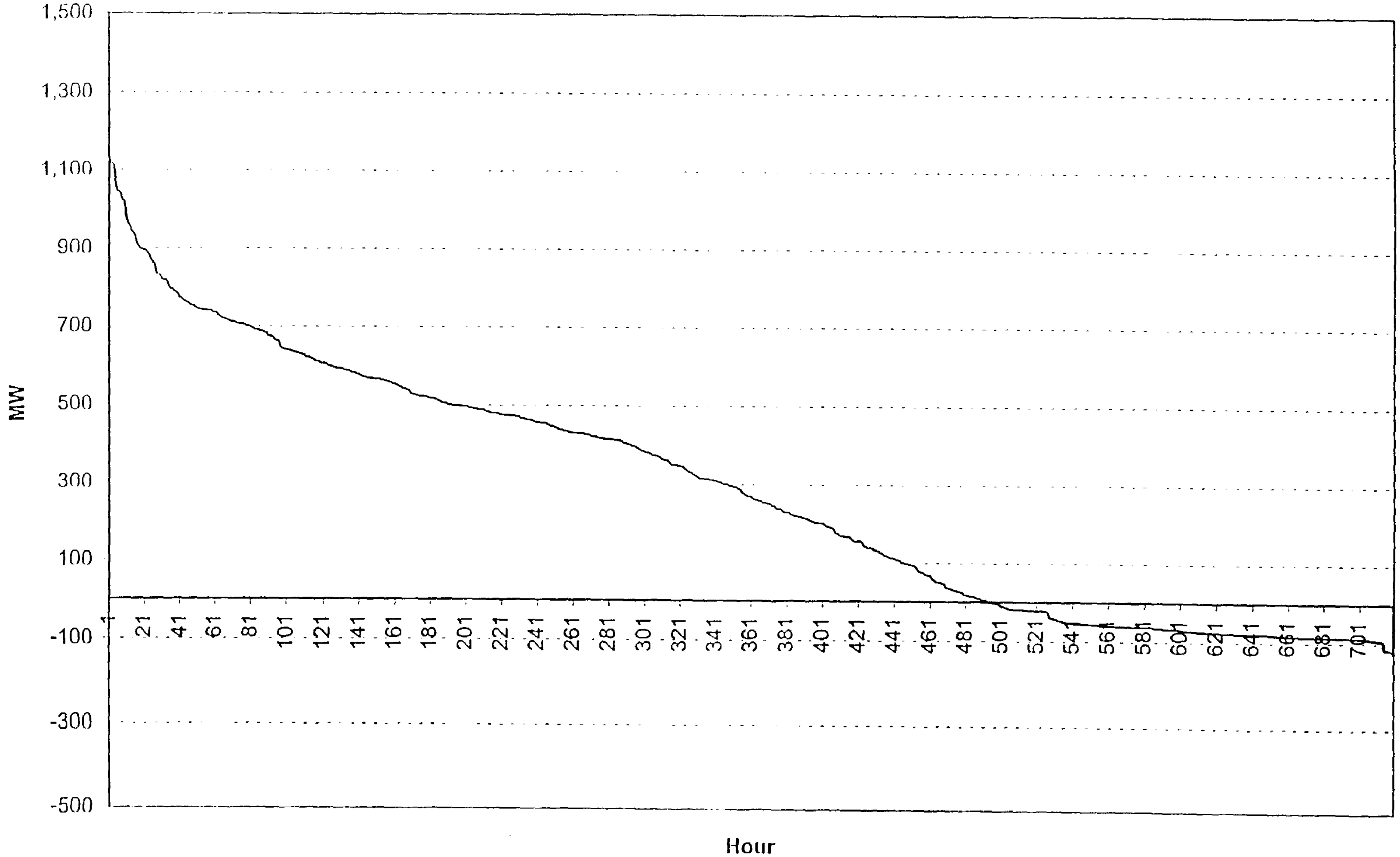
Western Area Power Administration
Green Book
Fig. 1-8

August
Long Term Average Generation



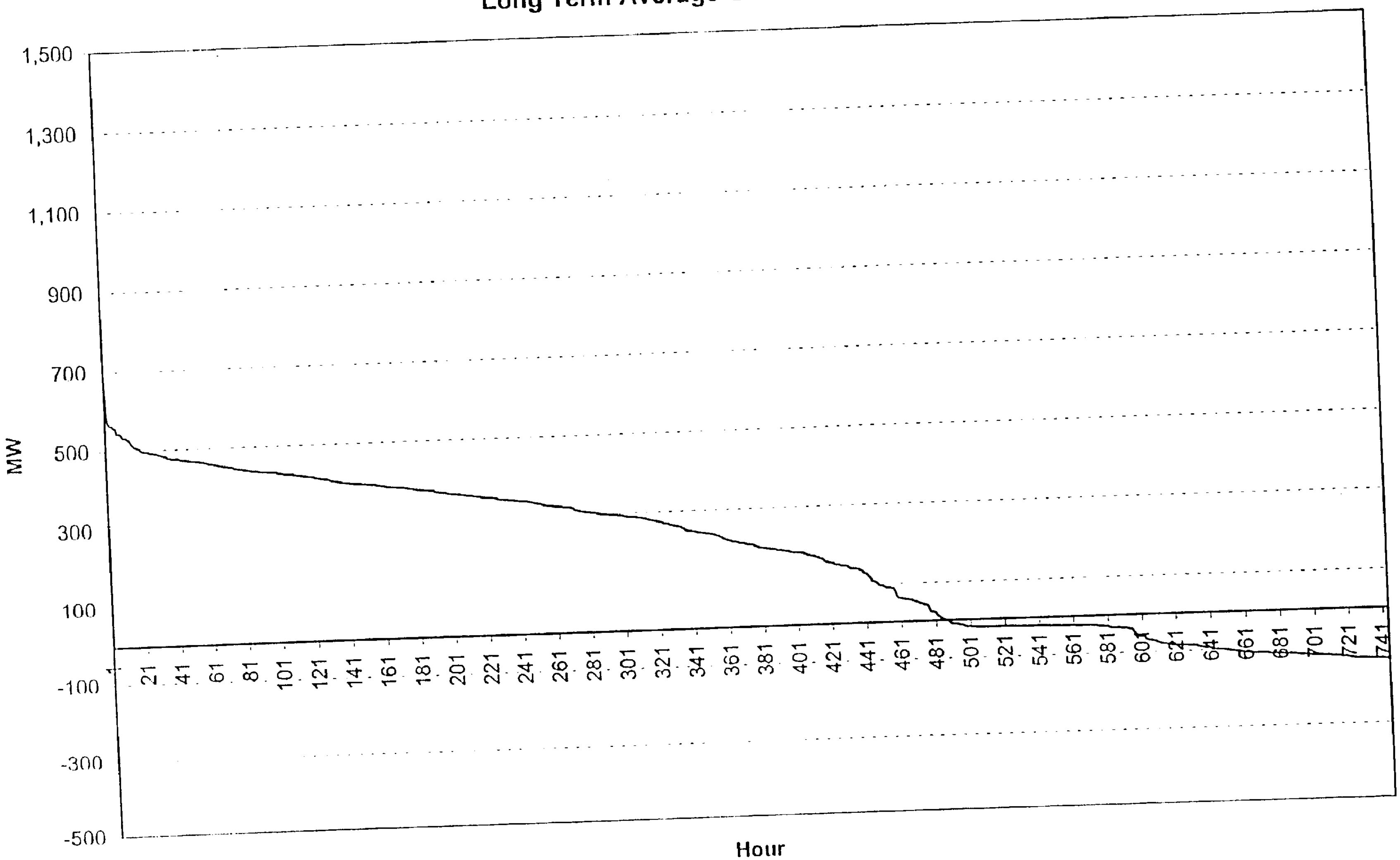
Western Area Power Administration
Green Book
Fig. 1-9

September
Long Term Average Generation



Western Area Power Administration
Green Book
Fig. 1-10

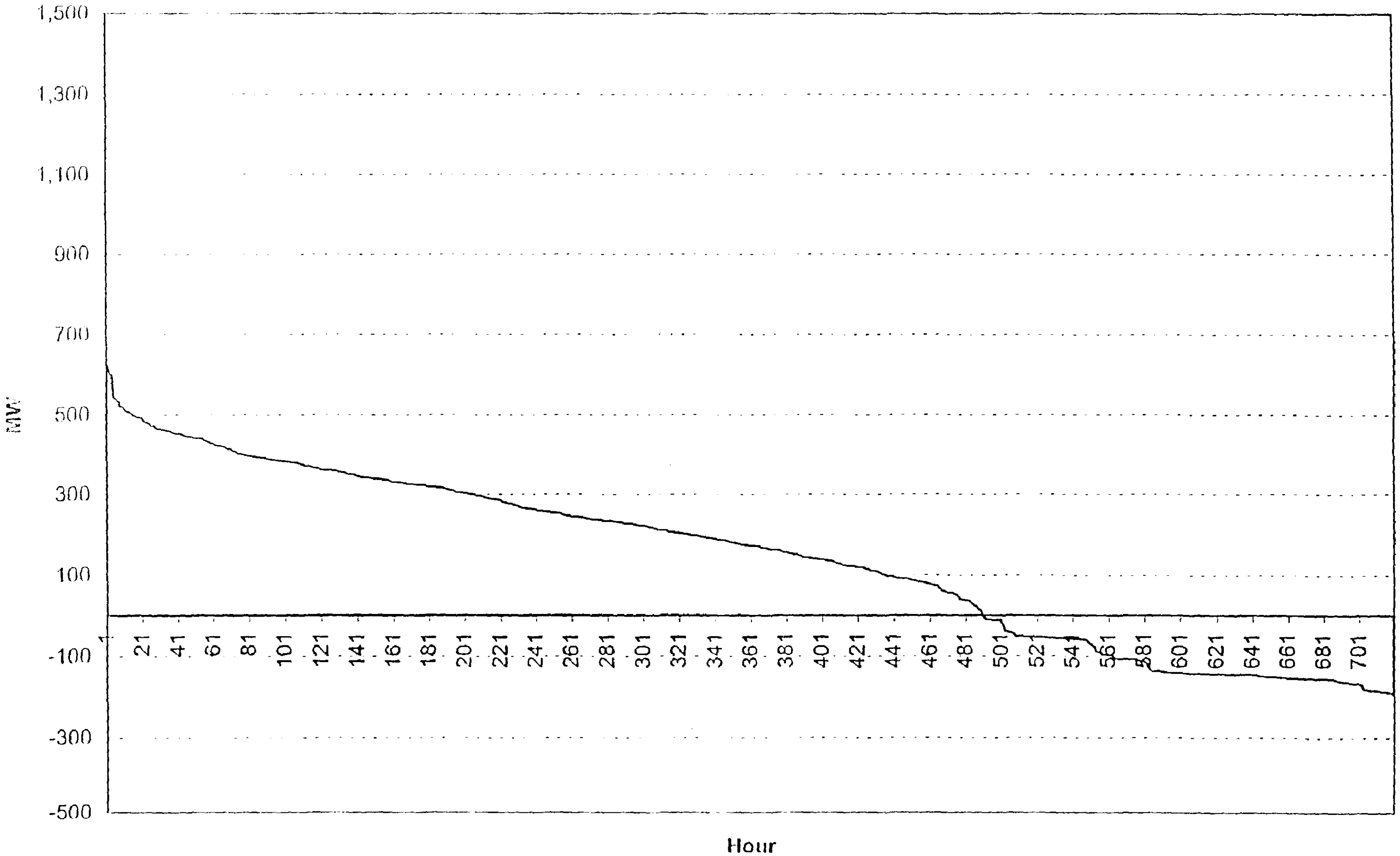
October
Long Term Average Generation



GreenBookdurationCurves.xls

Western Area Power Administration
Green Book
Fig. 1-11

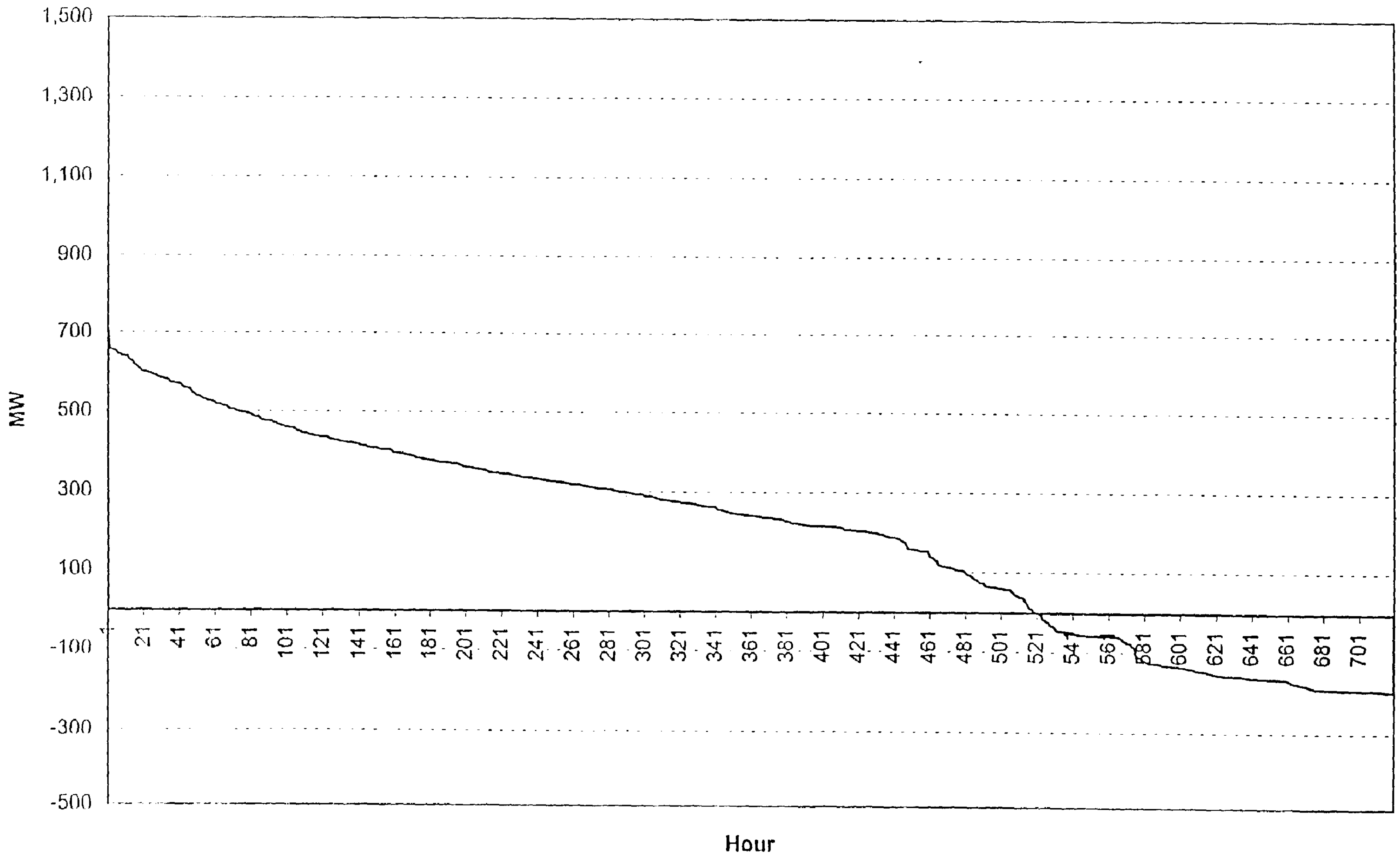
November
Long Term Average Generation



GreenBookdurationCurves.xls

Western Area Power Administration
Green Book
Fig. 1-12

December
Long Term Average Generation



GreenBookdurationCurves.xls

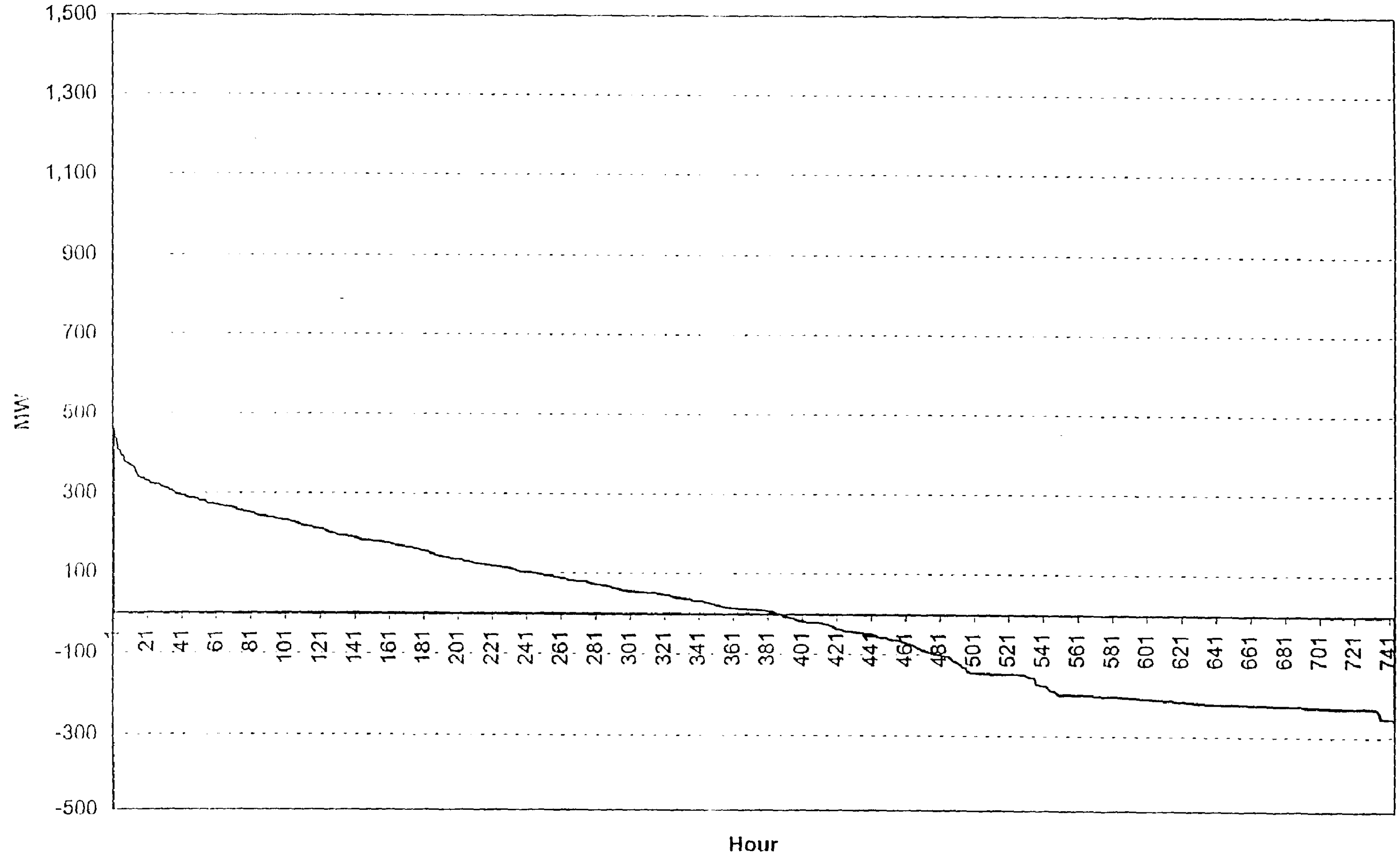
Monthly Generation Duration Curves

Dry Year Generation

Figures 2-1 thru 2-12

Western Area Power Administration
Green Book
Fig. 2-1

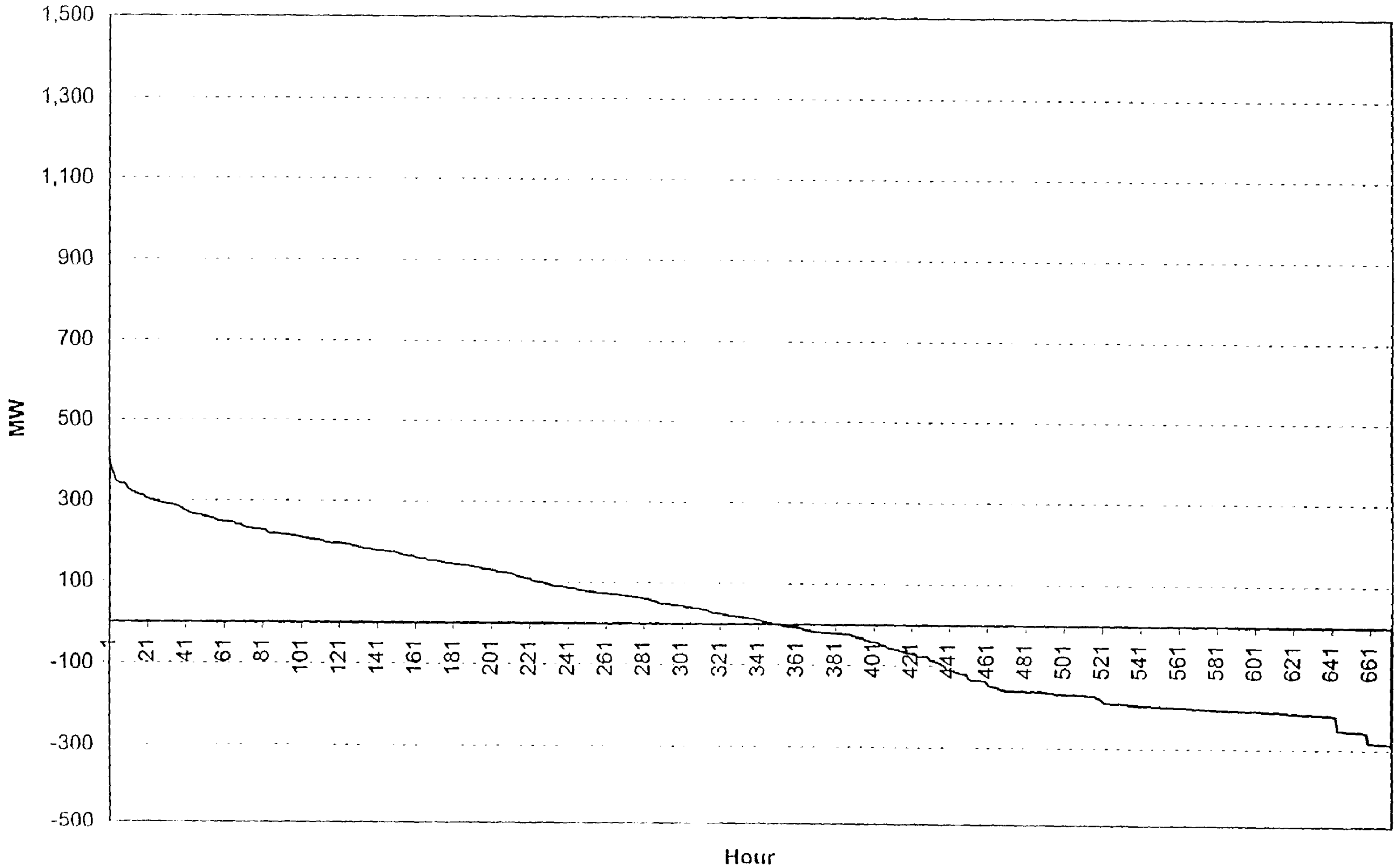
January
Rolling Dry Year Generation



GreenBookdurationCurves.xls

Western Area Power Administration
Green Book
Fig. 2-2

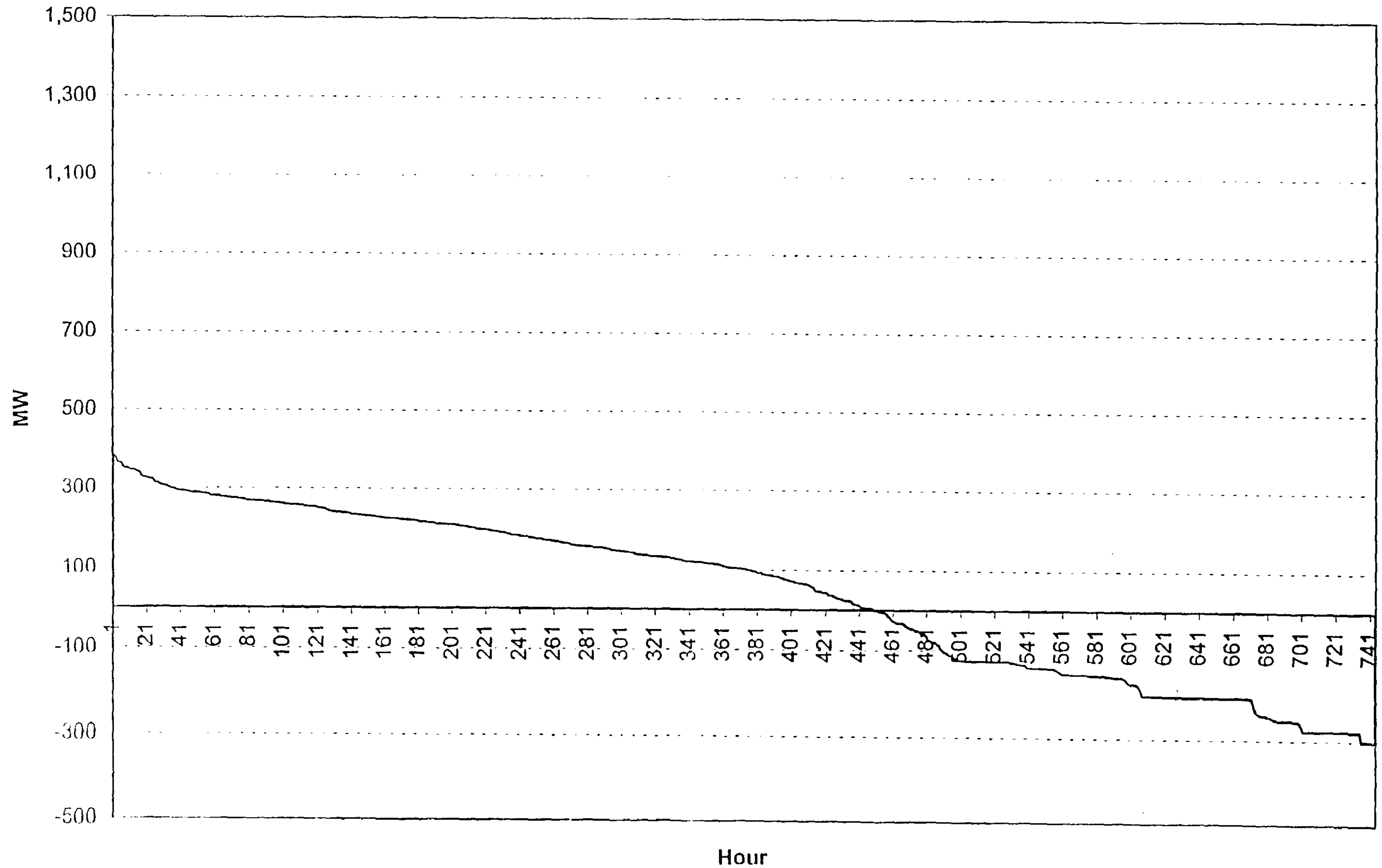
February
Rolling Dry Year Generation



GreenBookdurationCurves.xls

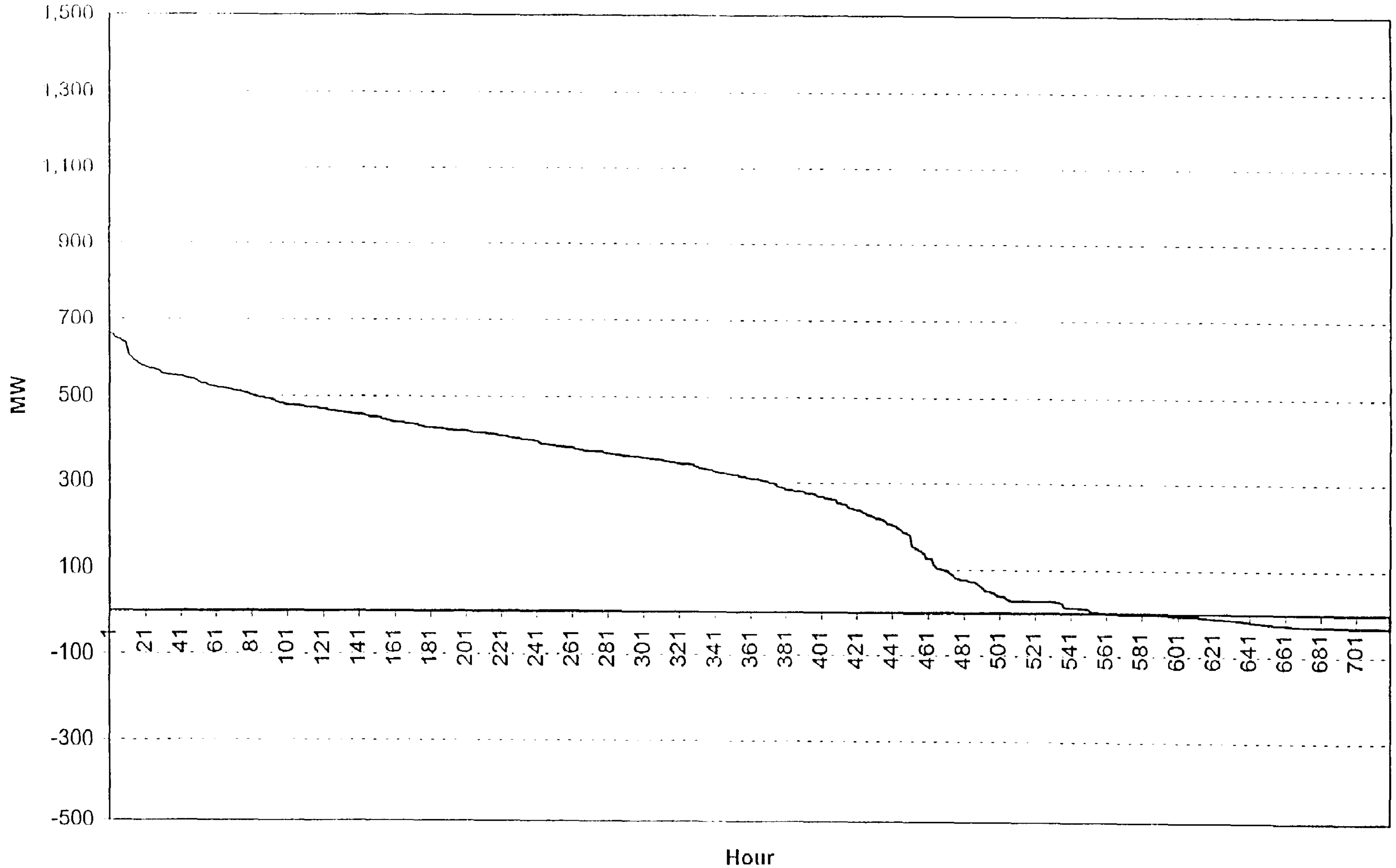
Wistern Area Power Administration
Green Book
Fig. 2-3

March
Rolling Dry Year Generation



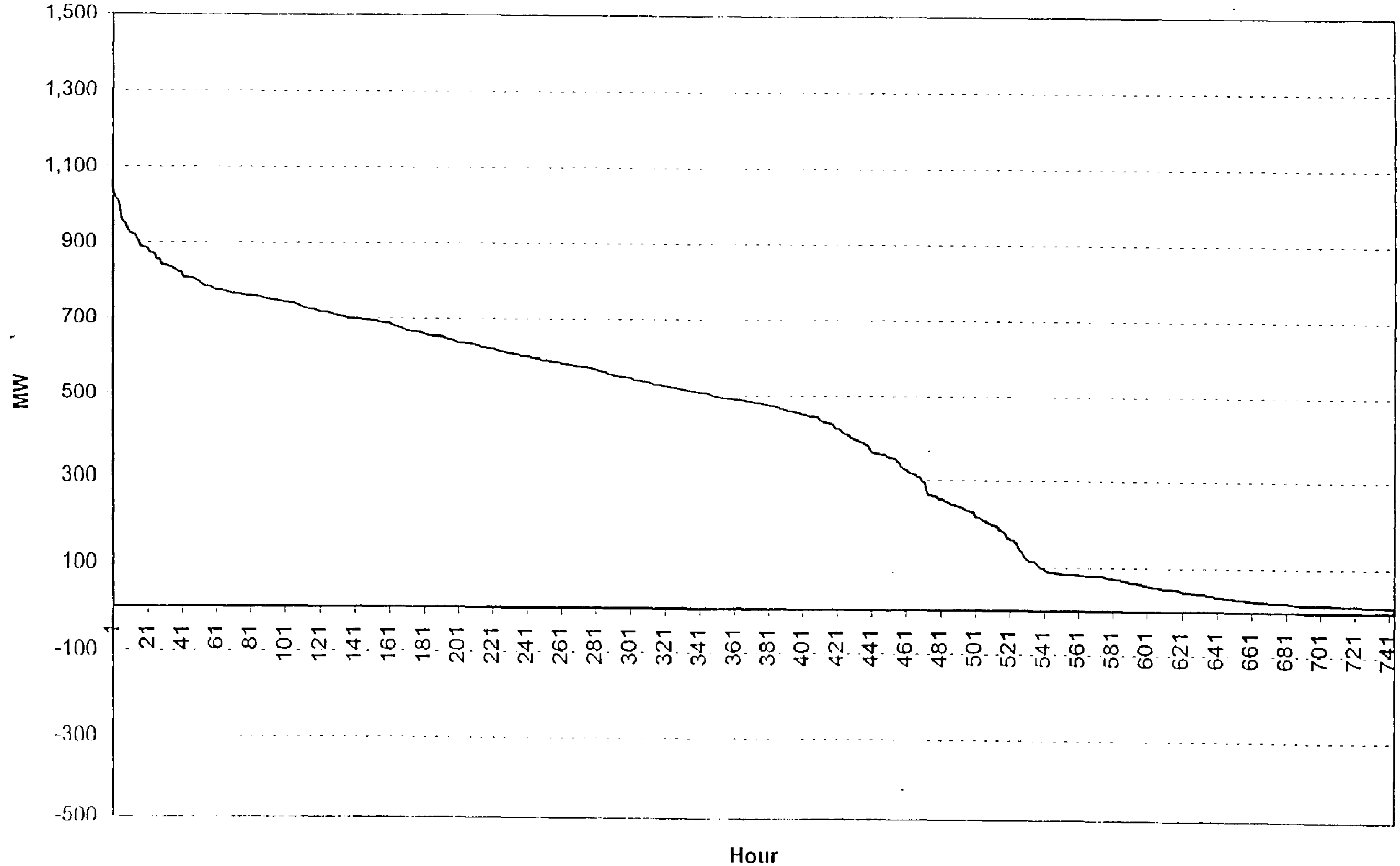
Western Area Power Administration
Green Book
Fig. 2-4

April
Rolling Dry Year Generation



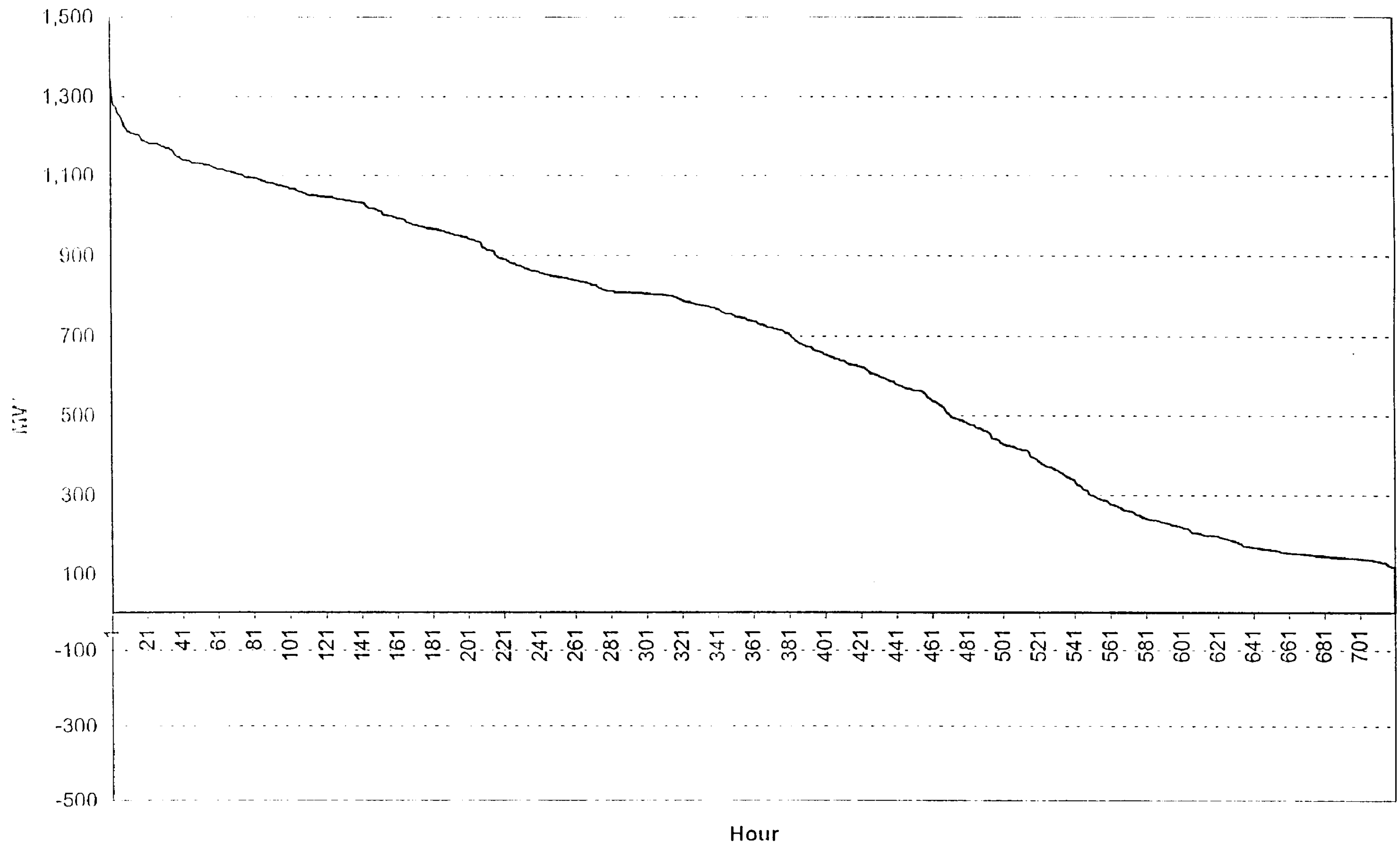
Western Area Power Administration
Green Book
Fig. 2-5

May
Rolling Dry Year Generation



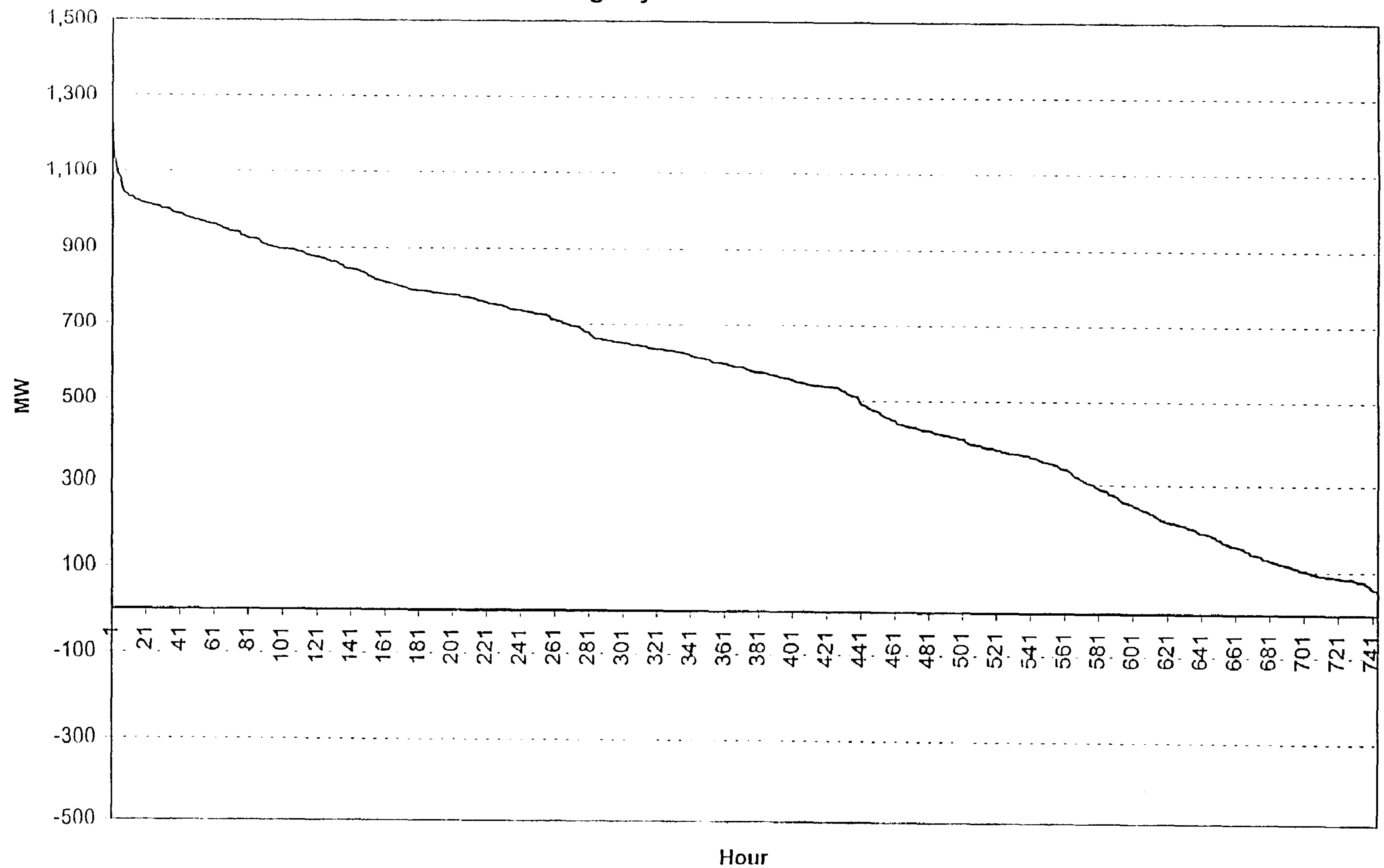
Western Area Power Administration
Green Book
Fig. 2-6

June
Rolling Dry Year Generation



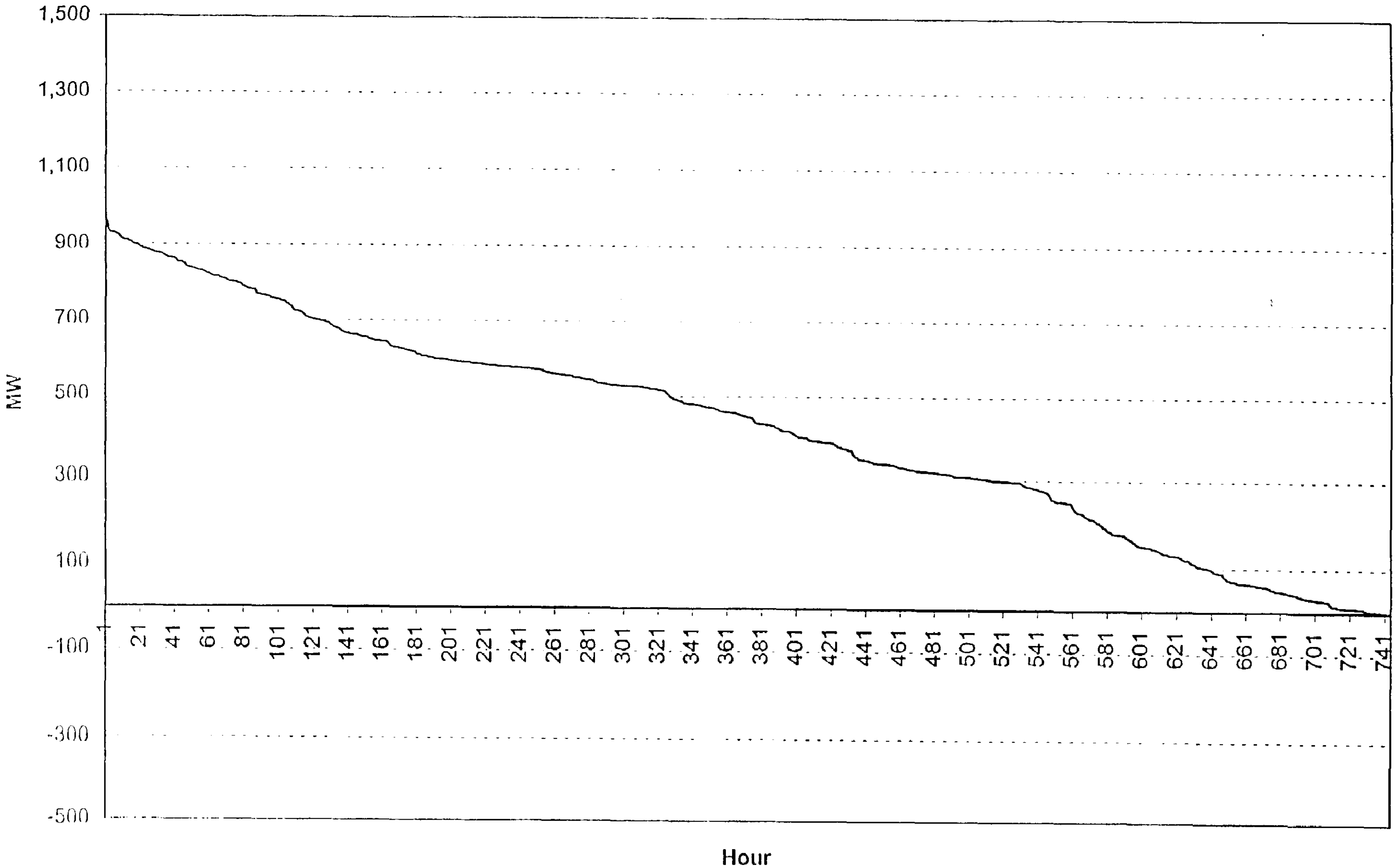
Western Area Power Administration
Green Book
Fig. 2-7

July
Rolling Dry Year Generation

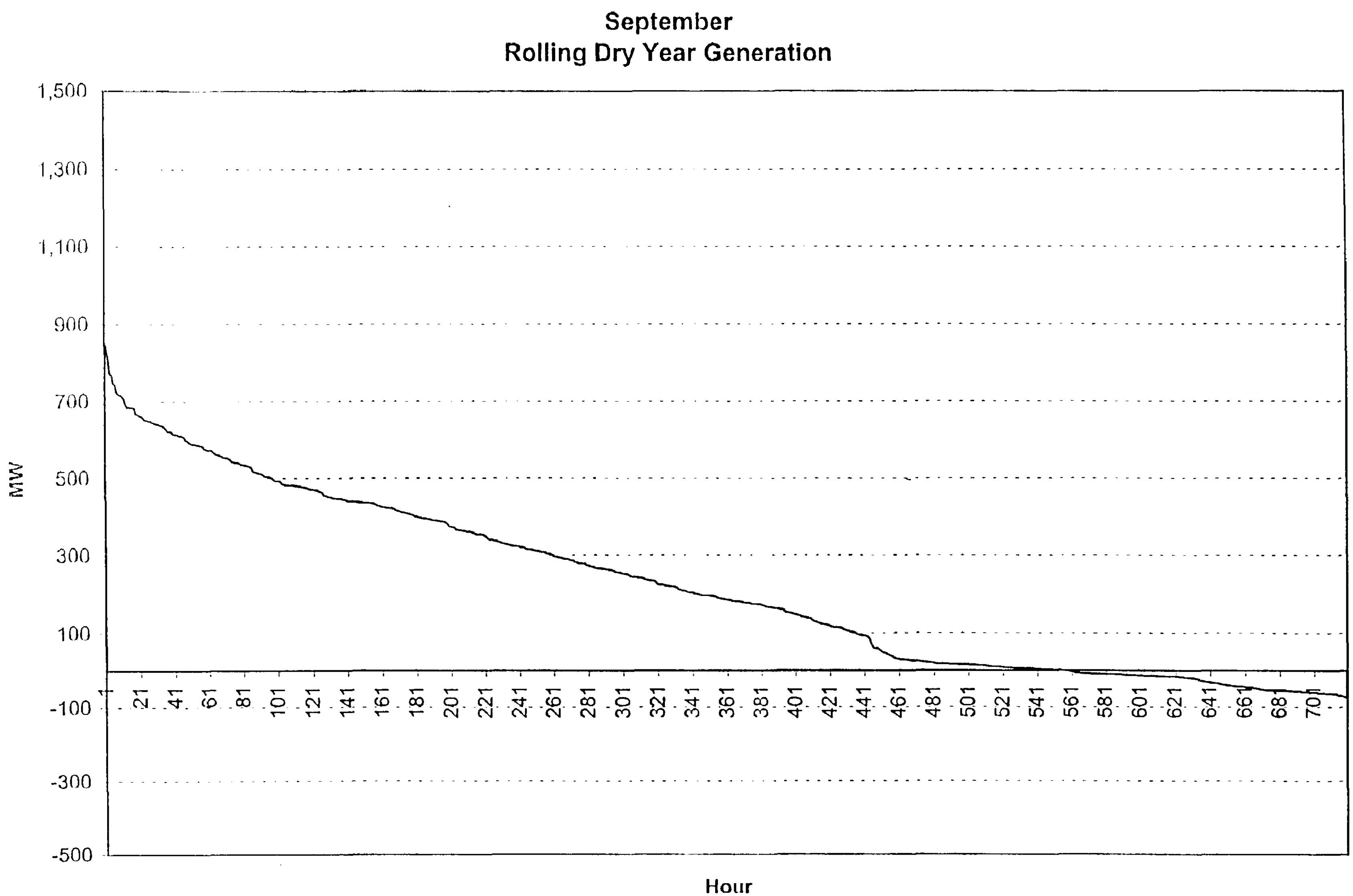


Western Area Power Administration
Green Book
Fig. 2-8

August
Rolling Dry Year Generation

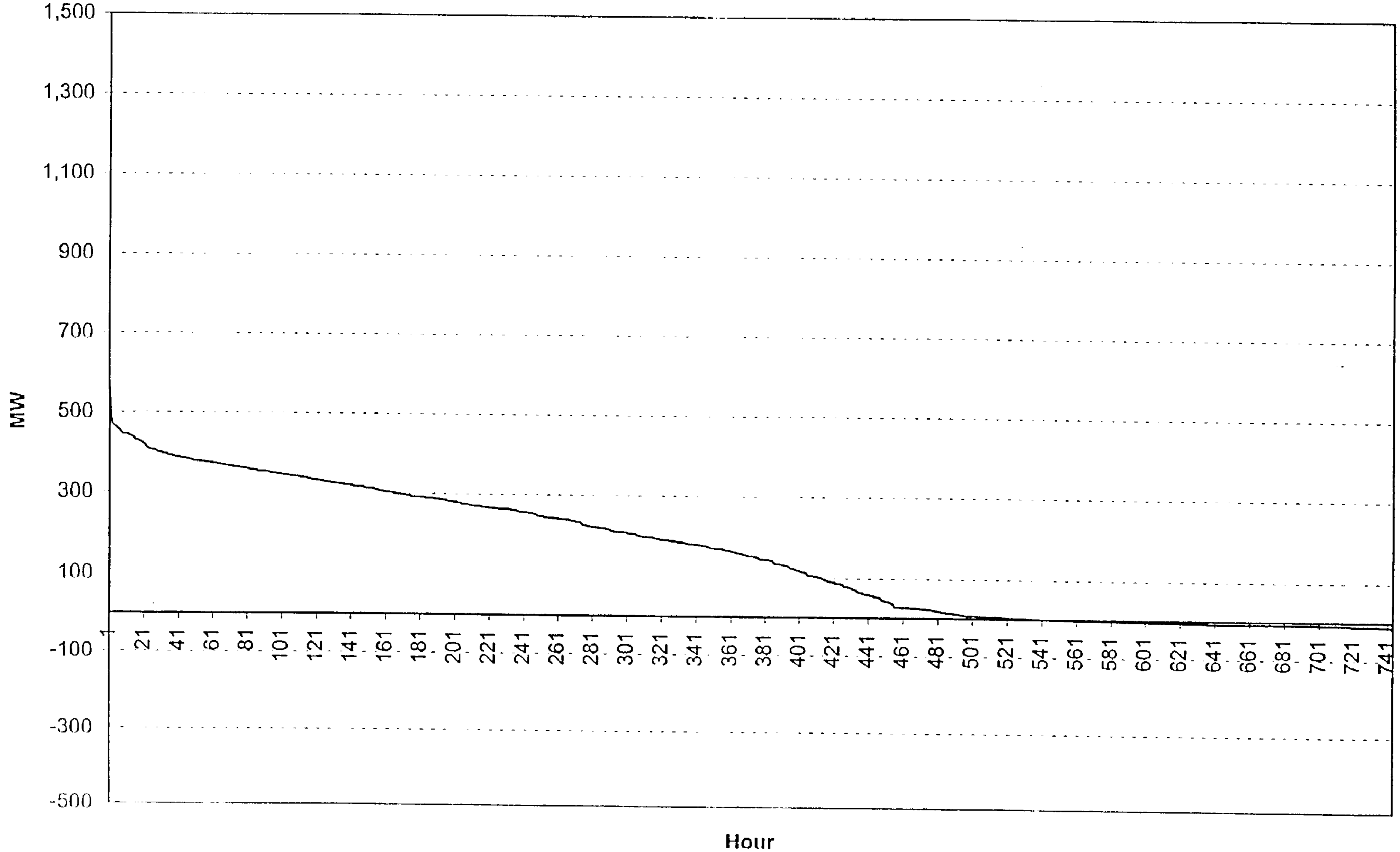


Western Area Power Administration
Green Book
Fig. 2-9



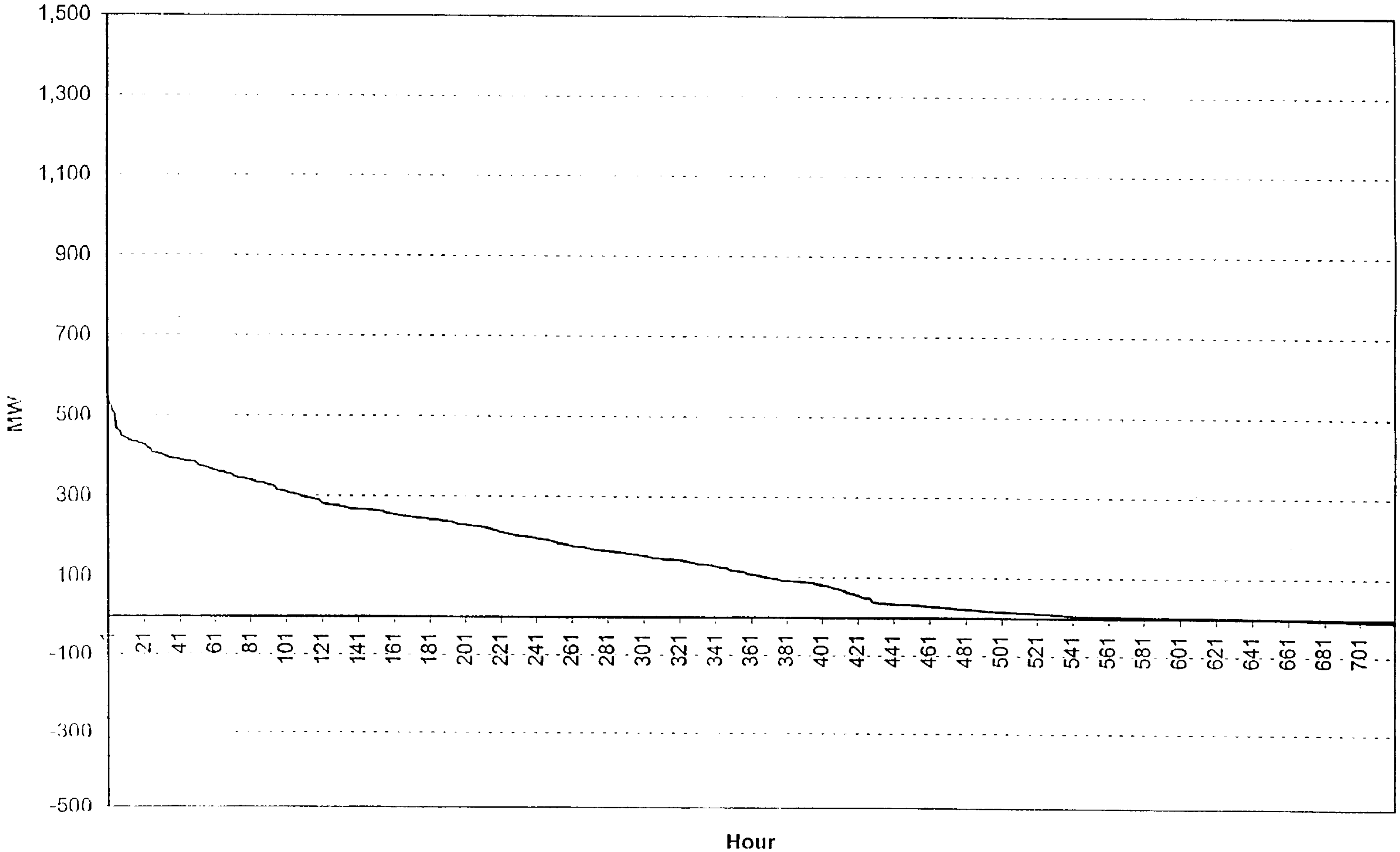
Western Area Power Administration
Green Book
Fig. 2-10

October
Rolling Dry Year Generation



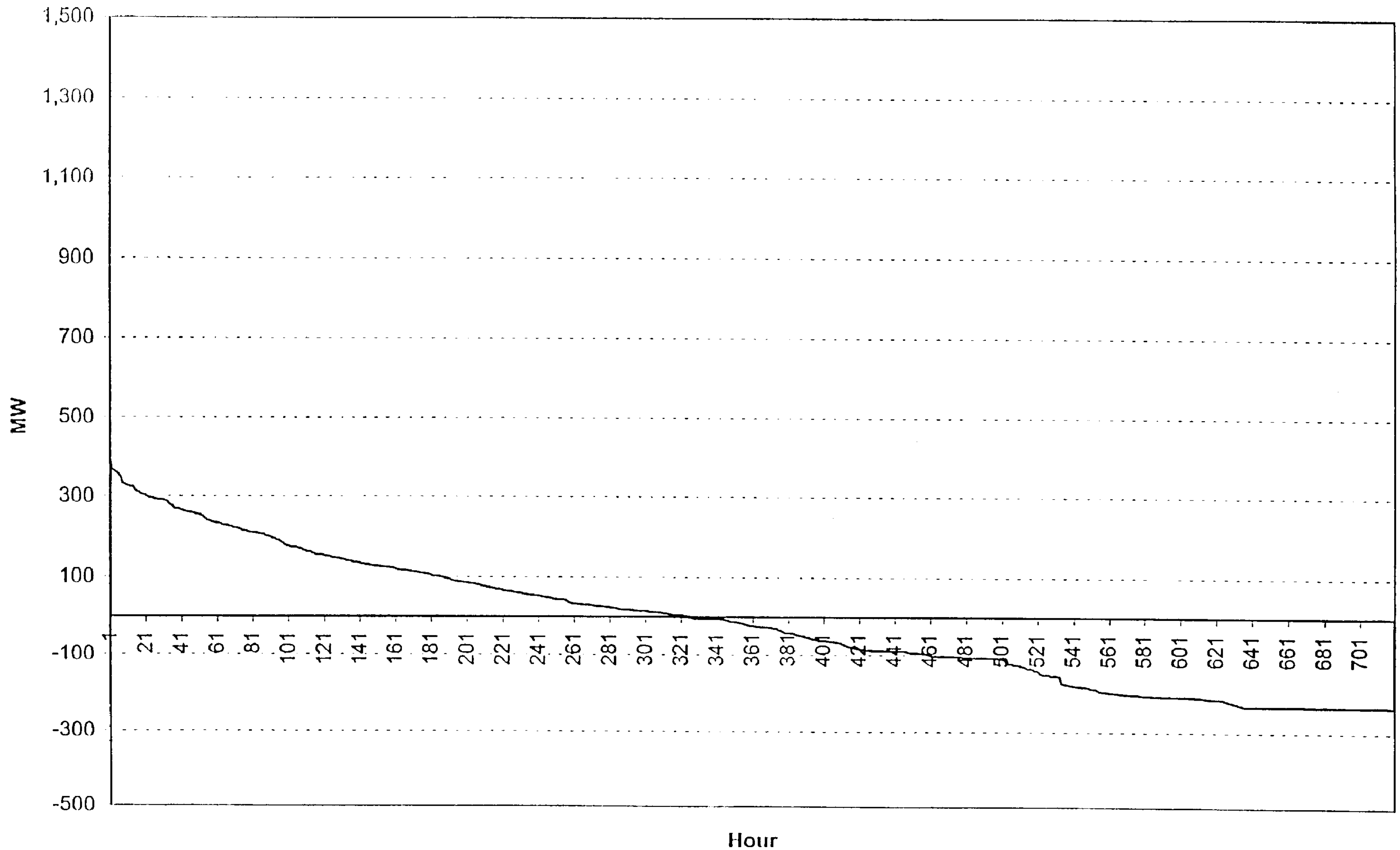
Western Area Power Administration
Green Book
Fig. 2-11

November
Rolling Dry Year Generation



Western Area Power Administration
Green Book
Fig. 2-12

December
Rolling Dry Year Generation



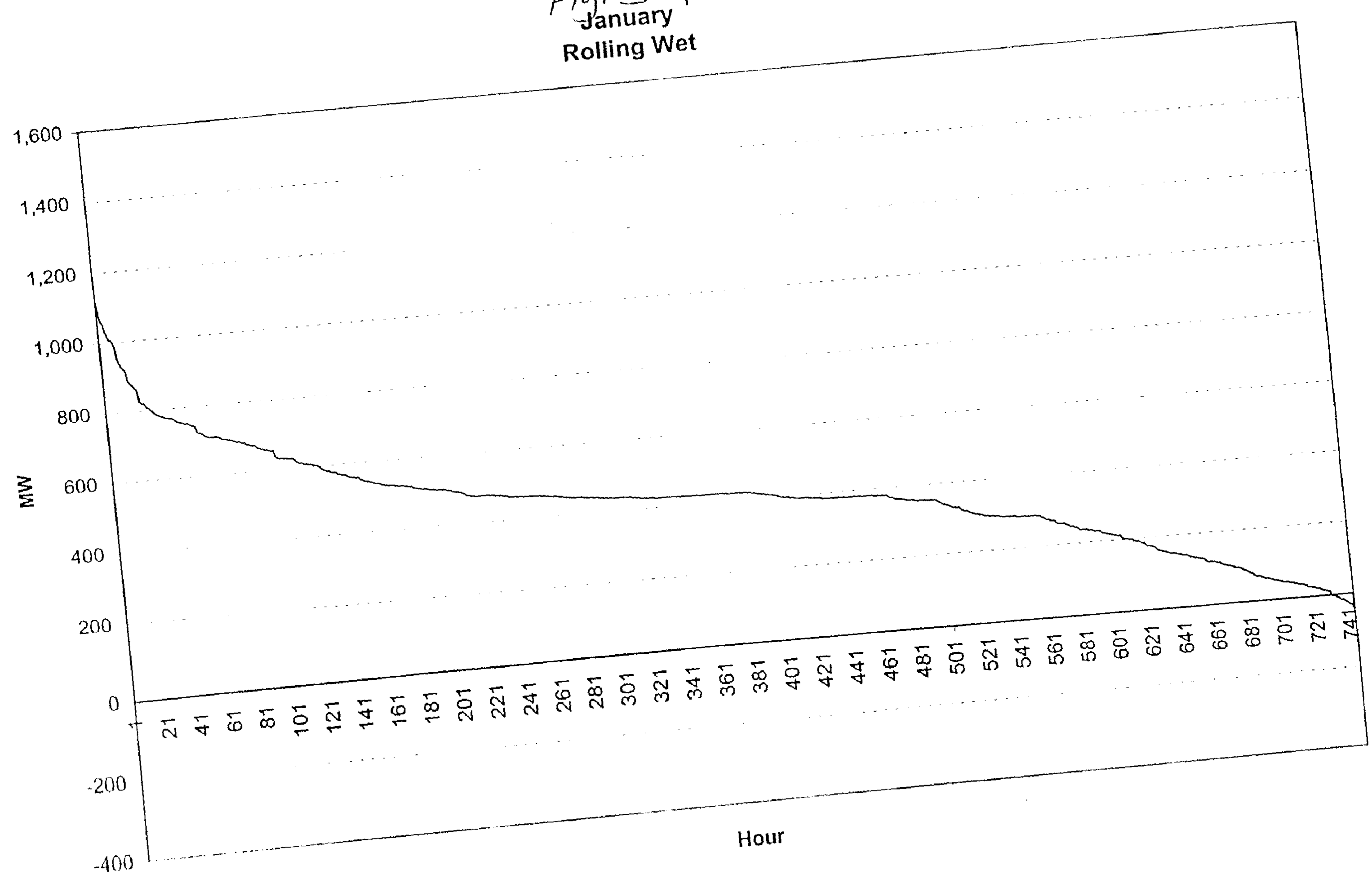
Monthly Generation Duration Curves

Wet Year Generation

Figures 3-1 thru 3-12

January (4)

WAPA - Green Book
Fig. 3-1



GenDur Curve2.xls

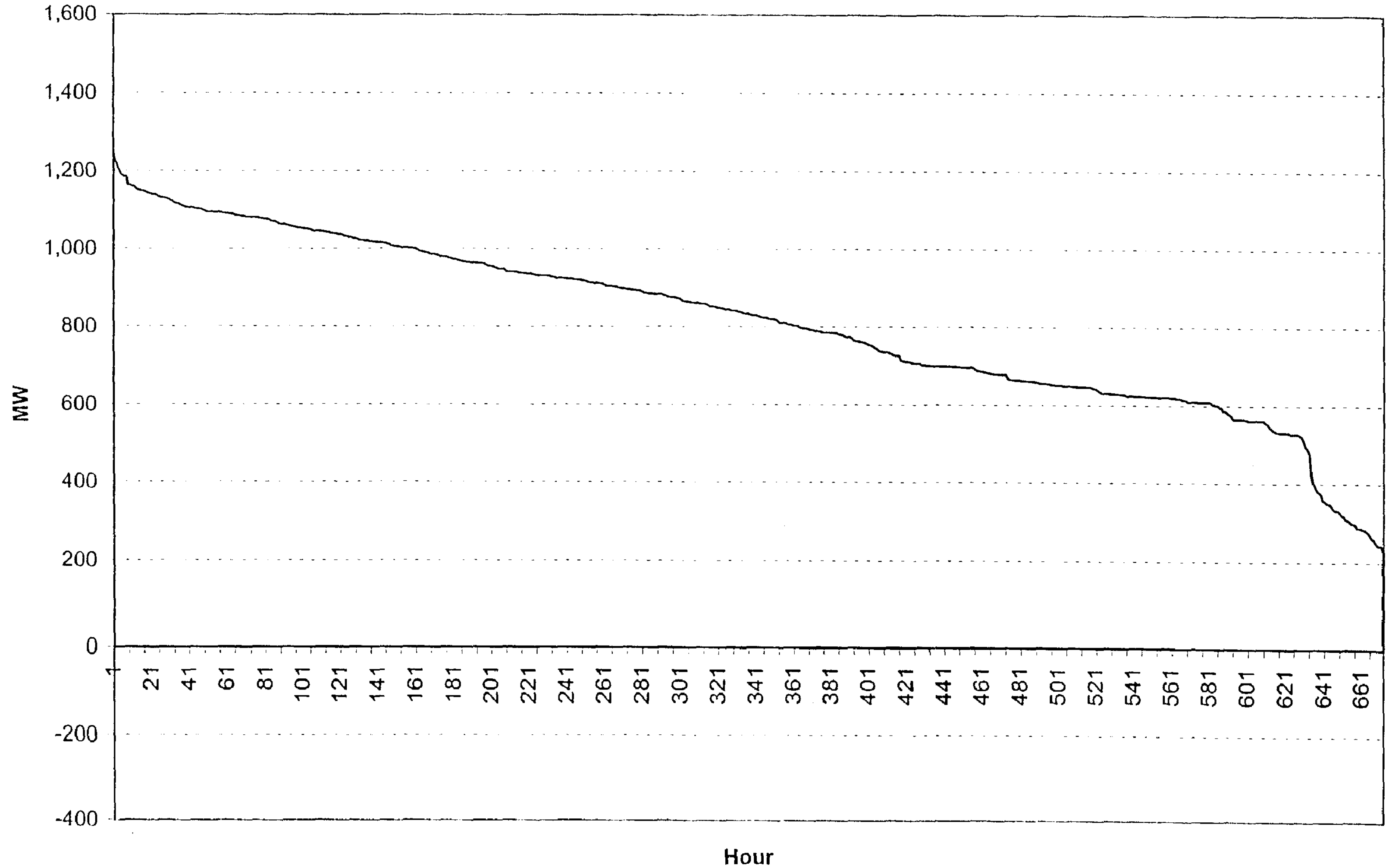
6/23/2000

February (4)

WAPA - Green Book

Fig. 3-2

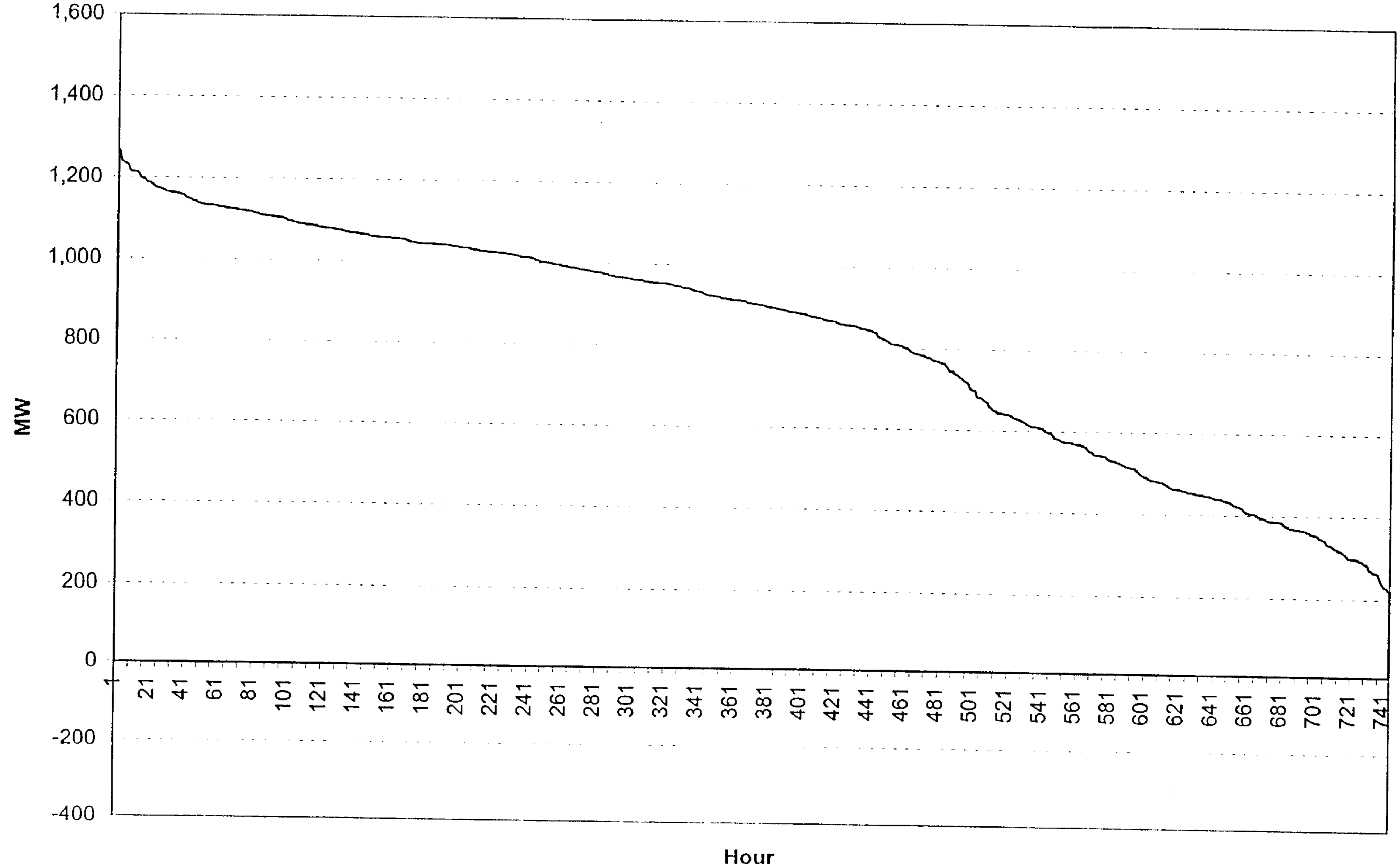
February
Rolling Wet



March (4)

WAPA - Green Book
Fig. 3-3

March
Rolling Wet



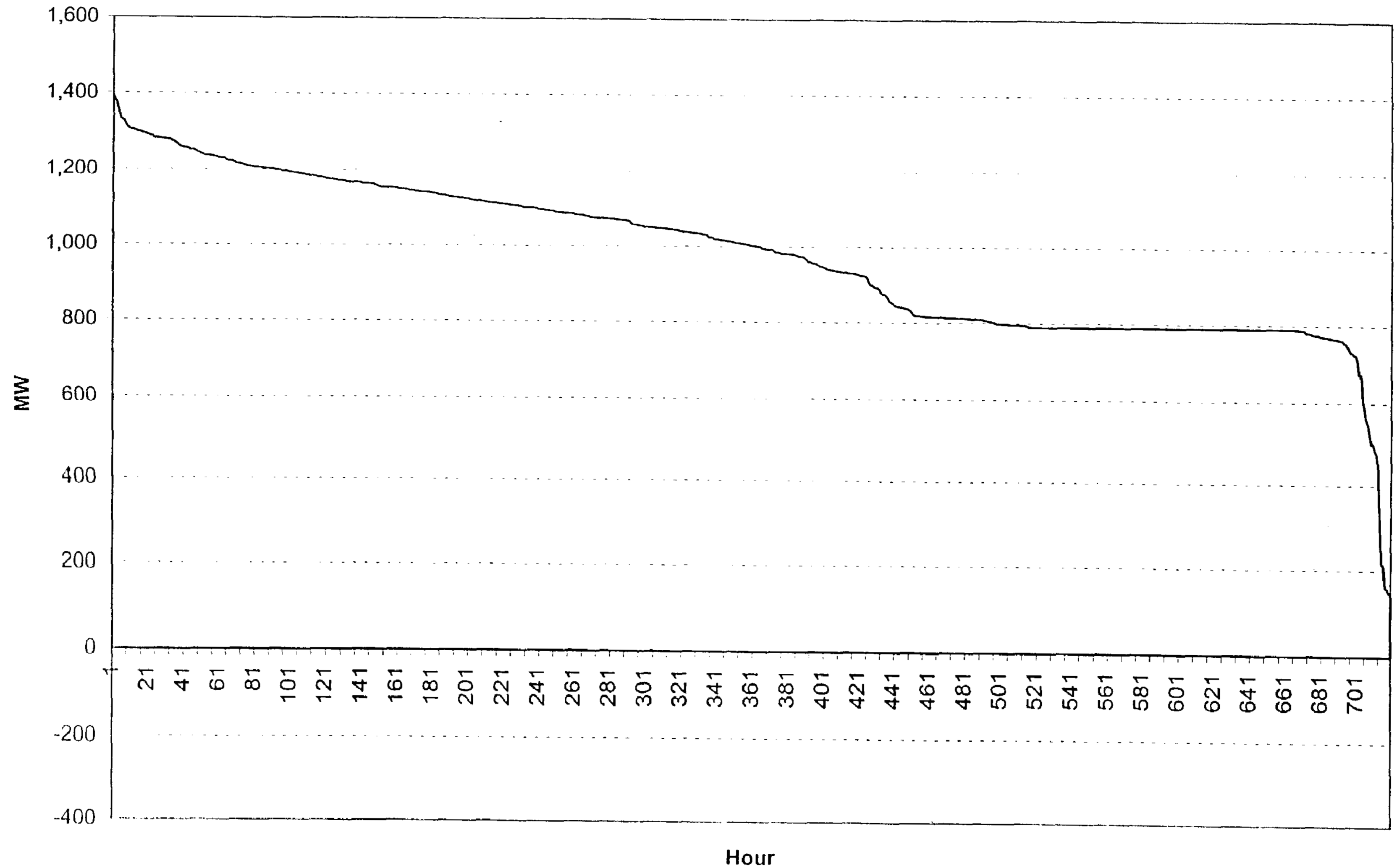
6/23/2000

GenDur Curve2.xls

April (4)

LUAPA - Green Book
Fig. 3-4

April
Rolling Wet



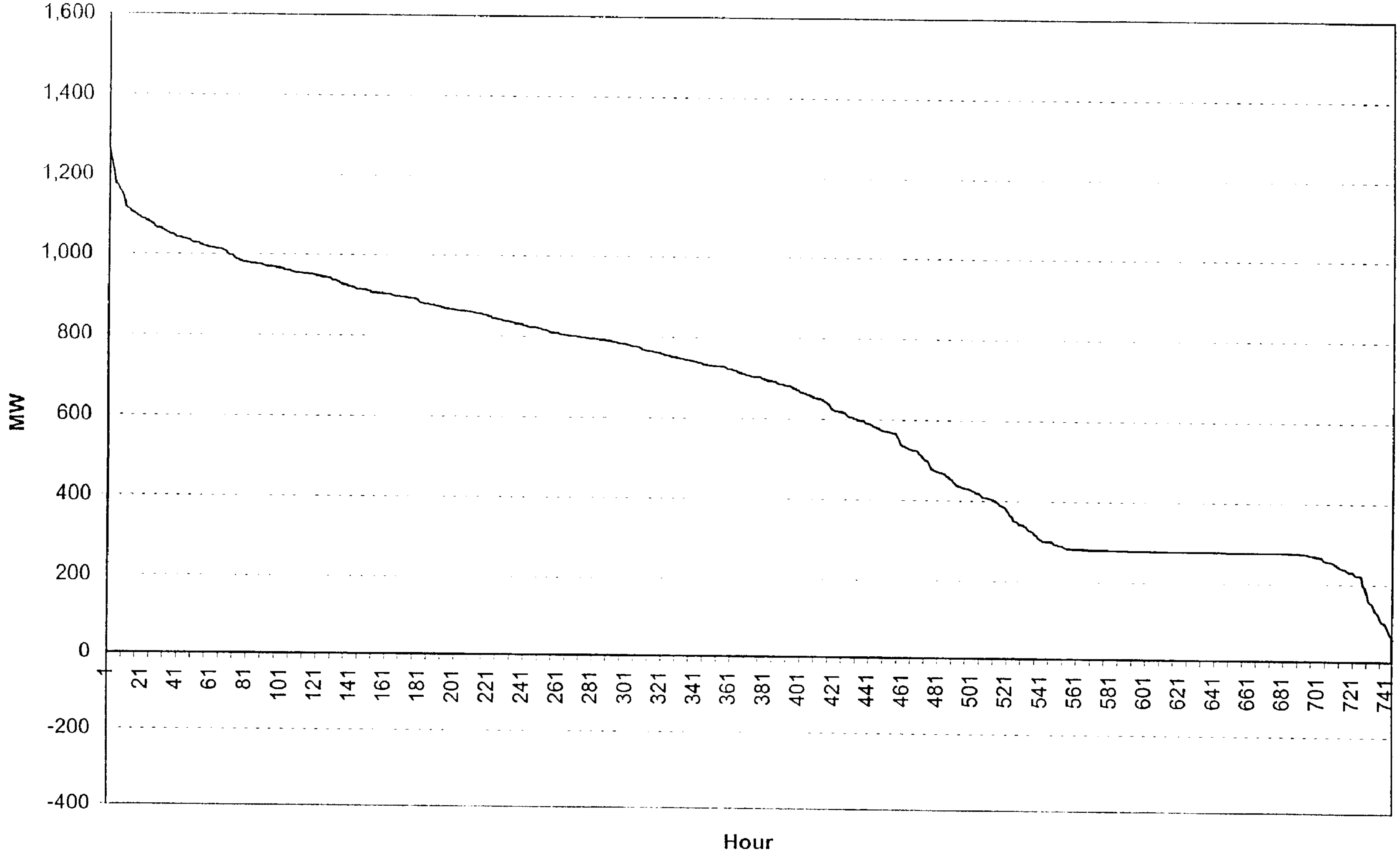
6/23/2000

GenDur Curve2.xls

May (4)

WAPA - Green Book
Fig. 3-5

May
Rolling Wet



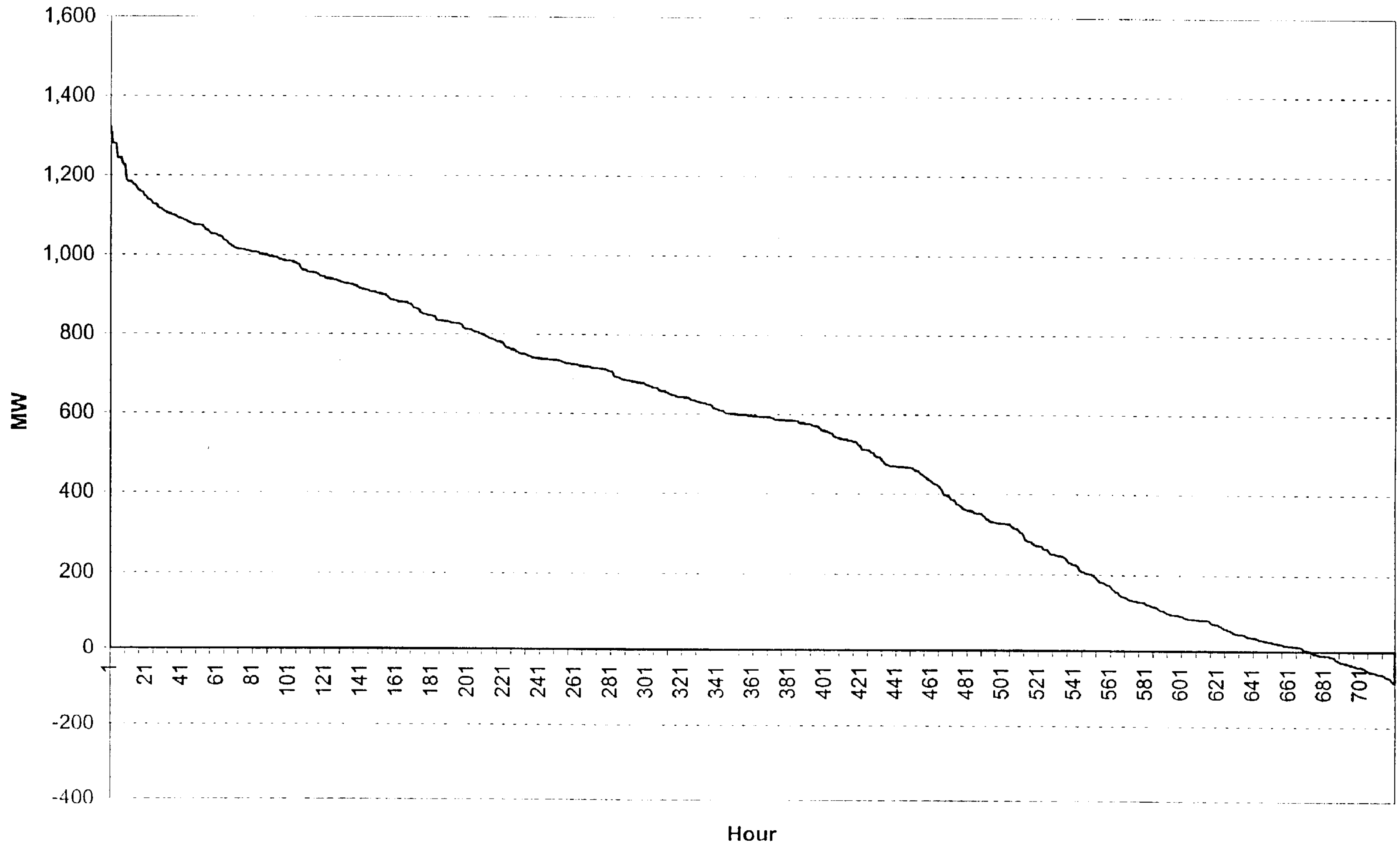
6/23/2000

GenDur Curve2.xls

June (4)

WAPA - Green Book
Fig 3-6

June
Rolling Wet

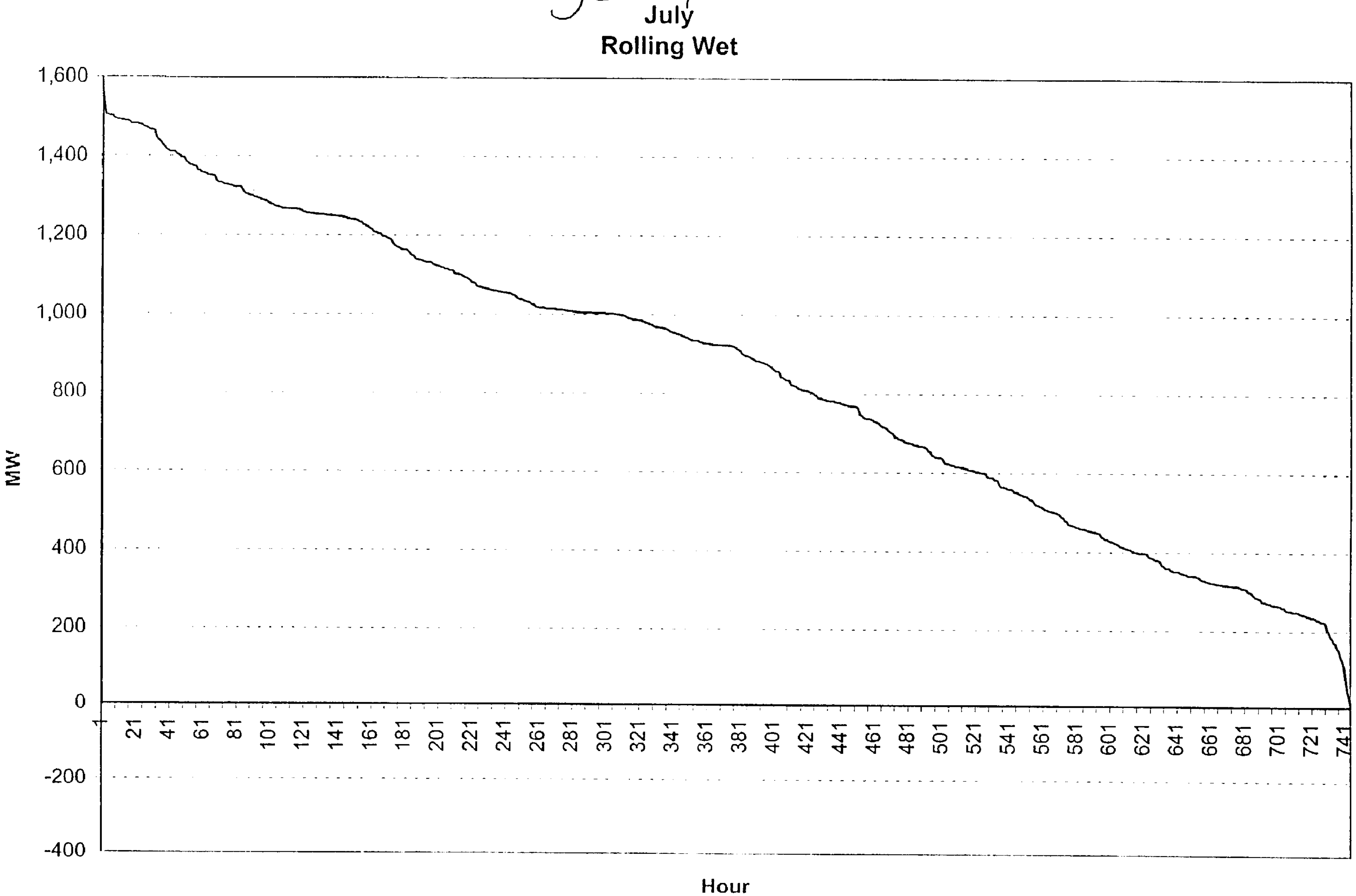


6/23/2000

GenDur Curve2.xls

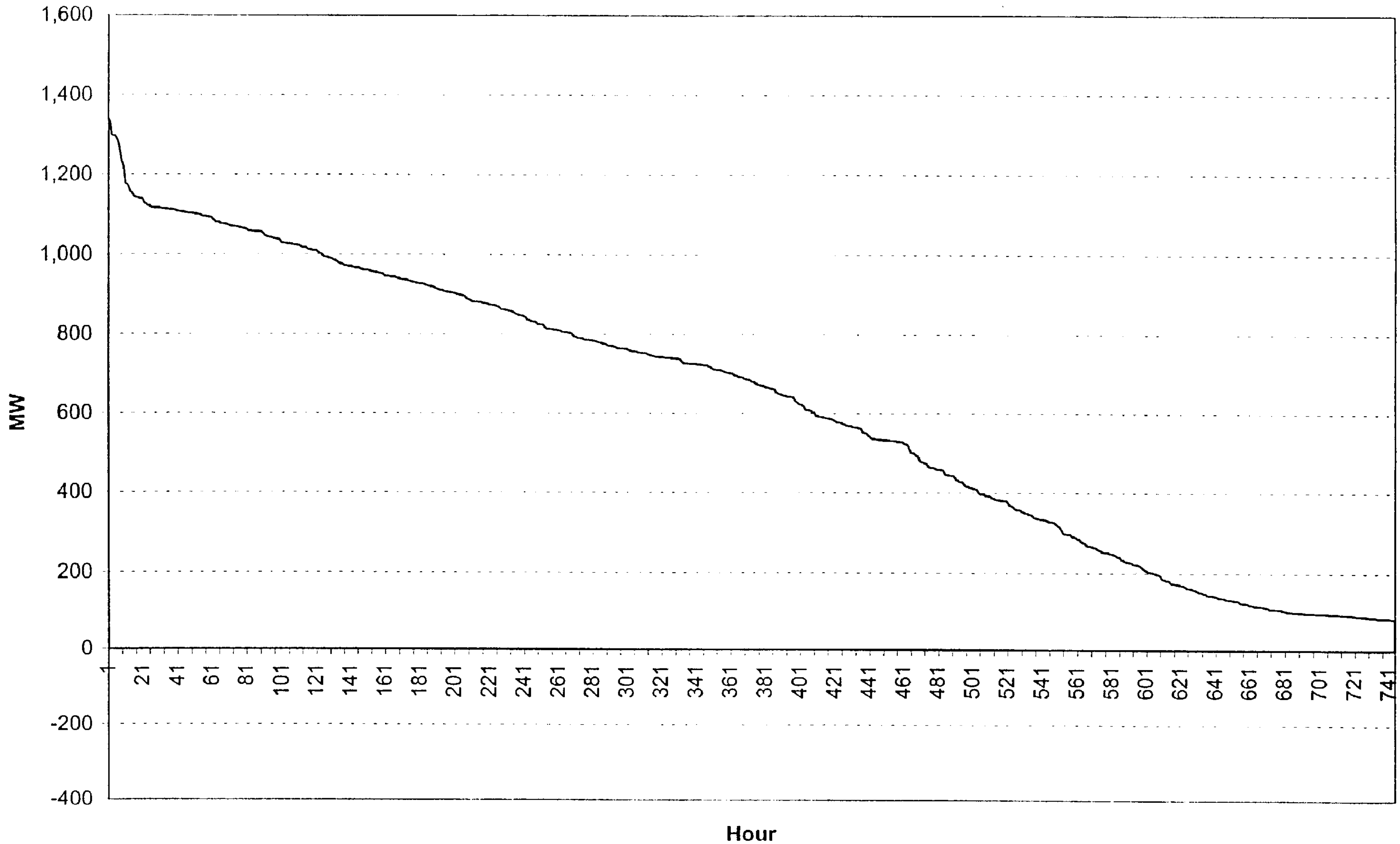
July (4)

WAPA- Green Book Fig 3.-7

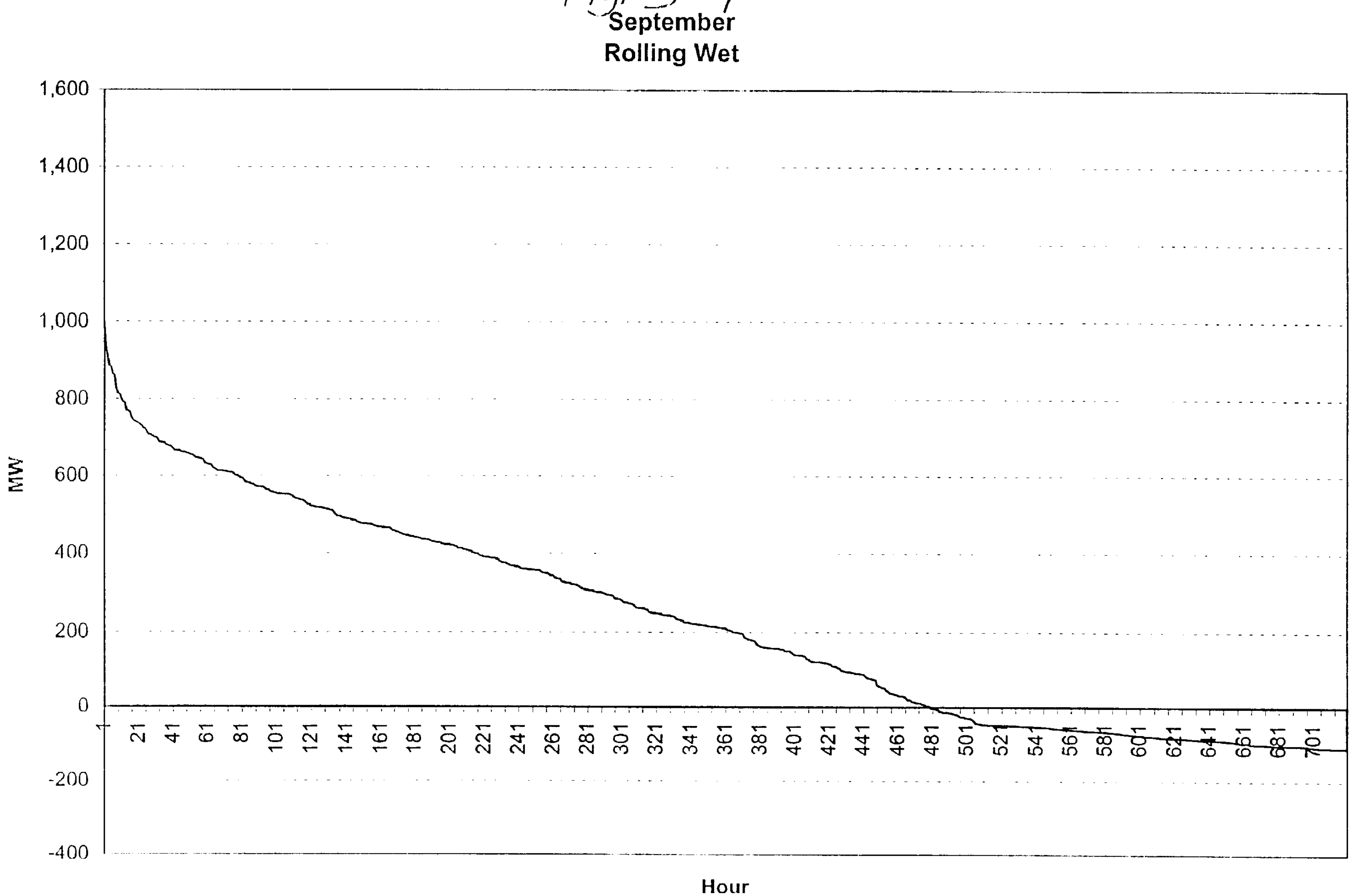


WAPA - Green Book
Fig. 3-8

August
Rolling Wet



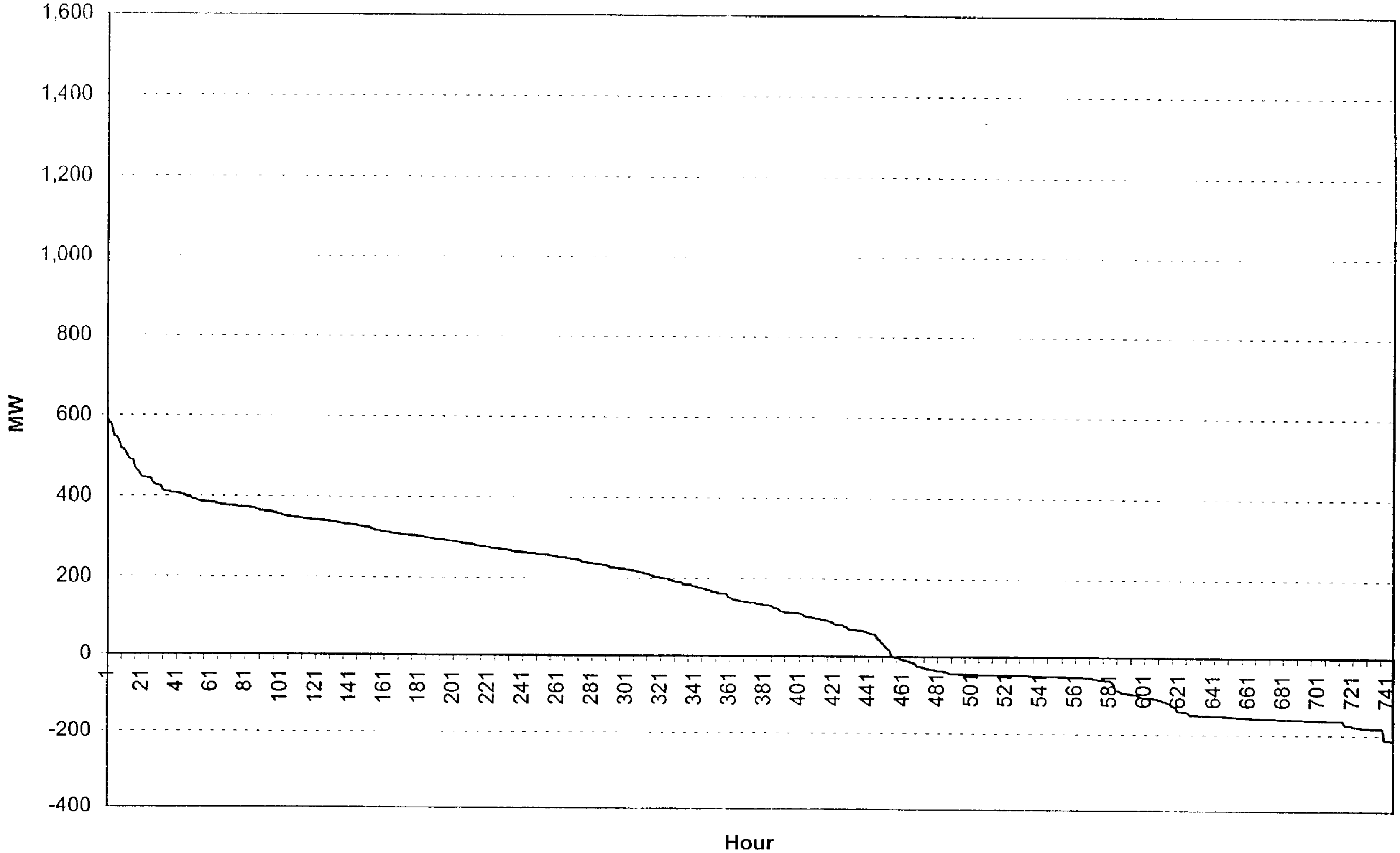
WAPA - Green Book
Fig. 3-9



October (4)

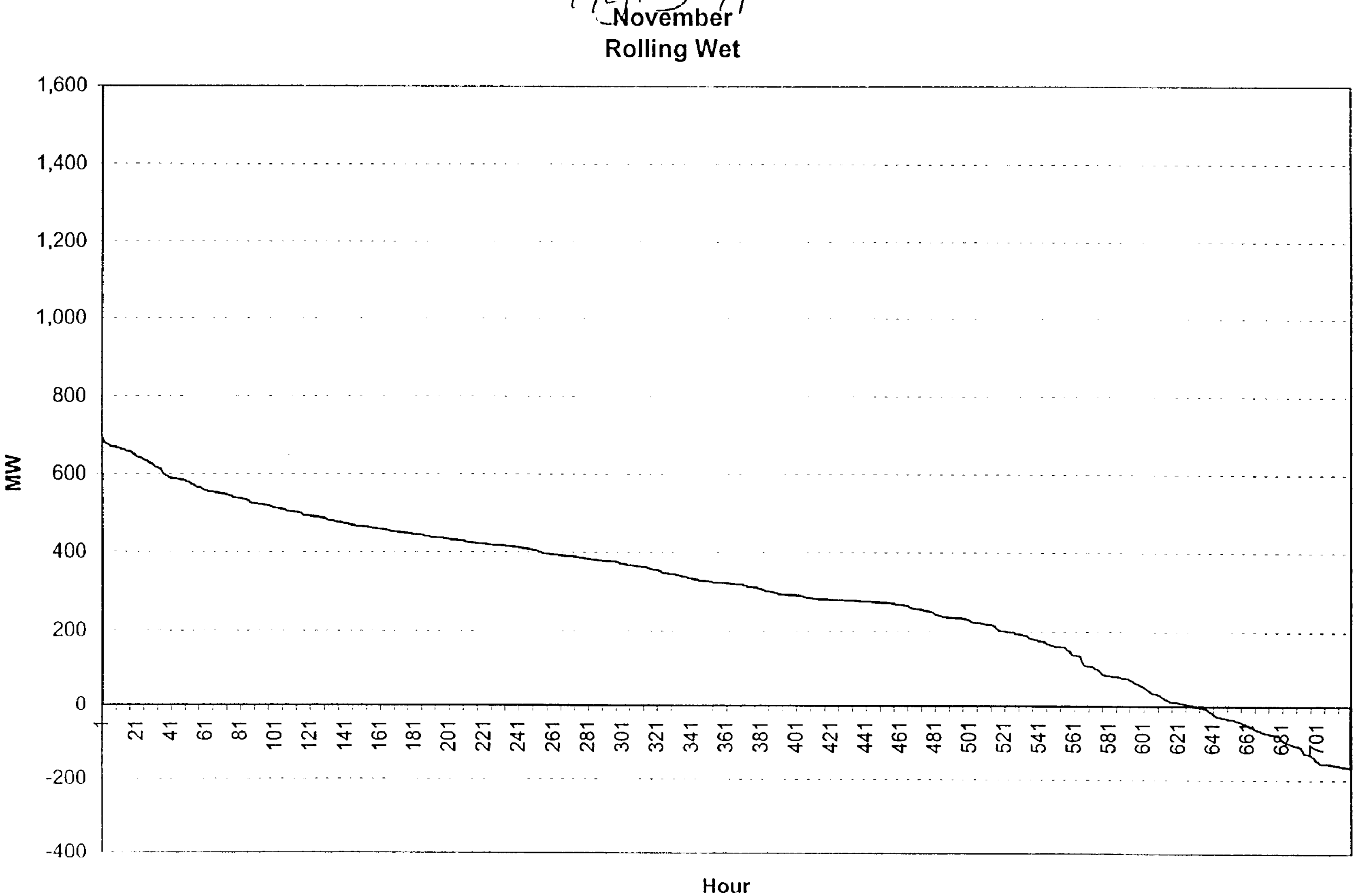
WAPA - Green Book
Fig. 3-10

October
Rolling Wet



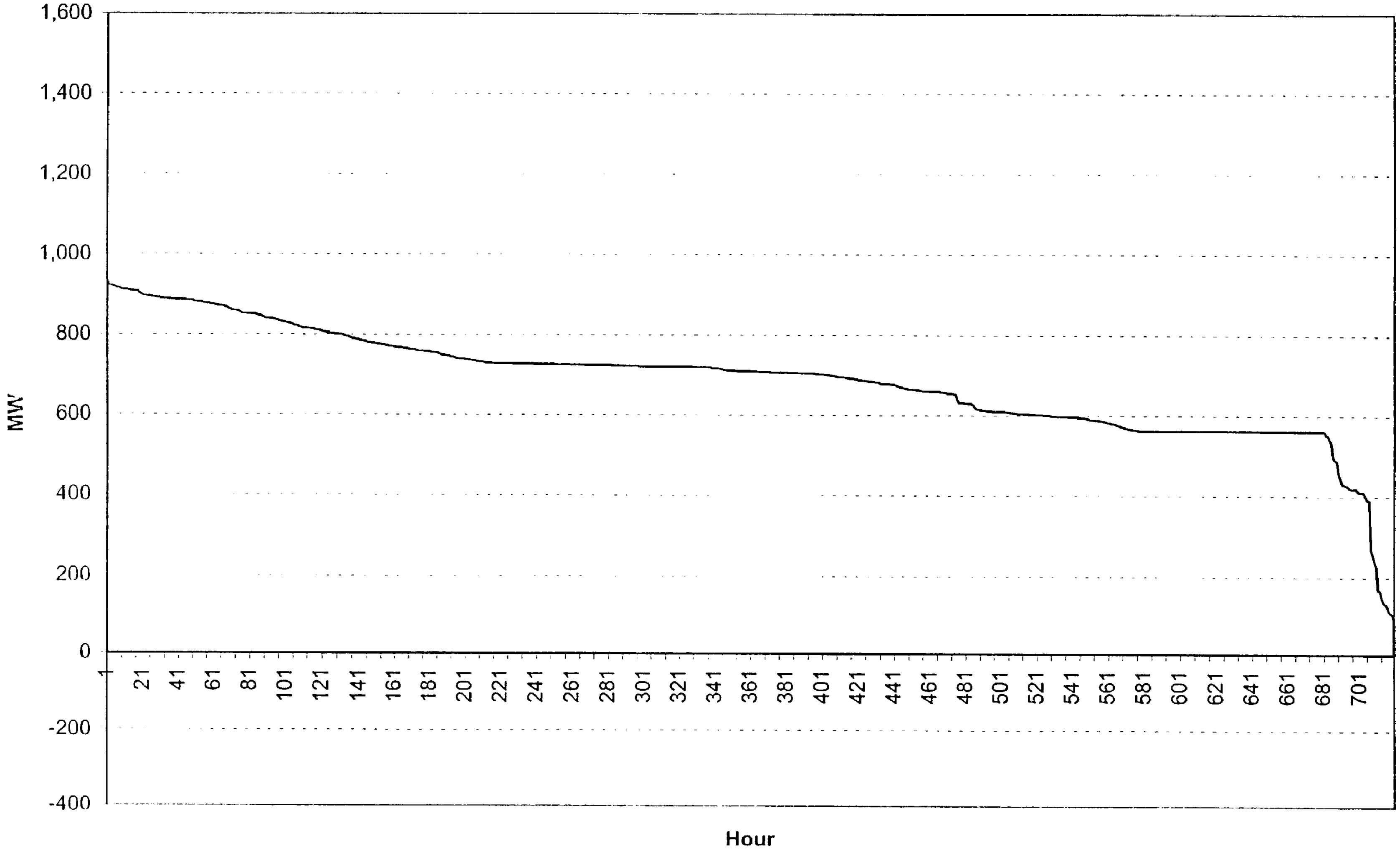
November (4)

WAPA - Green Book
Fig. 3-11



WAPA - Green Book
Fig. 3-12

December
Rolling Wet



Daily Generation Profile

Average Generation

Peak Weekday

Figures 4-1 thru 4-12

Fig. 4-1

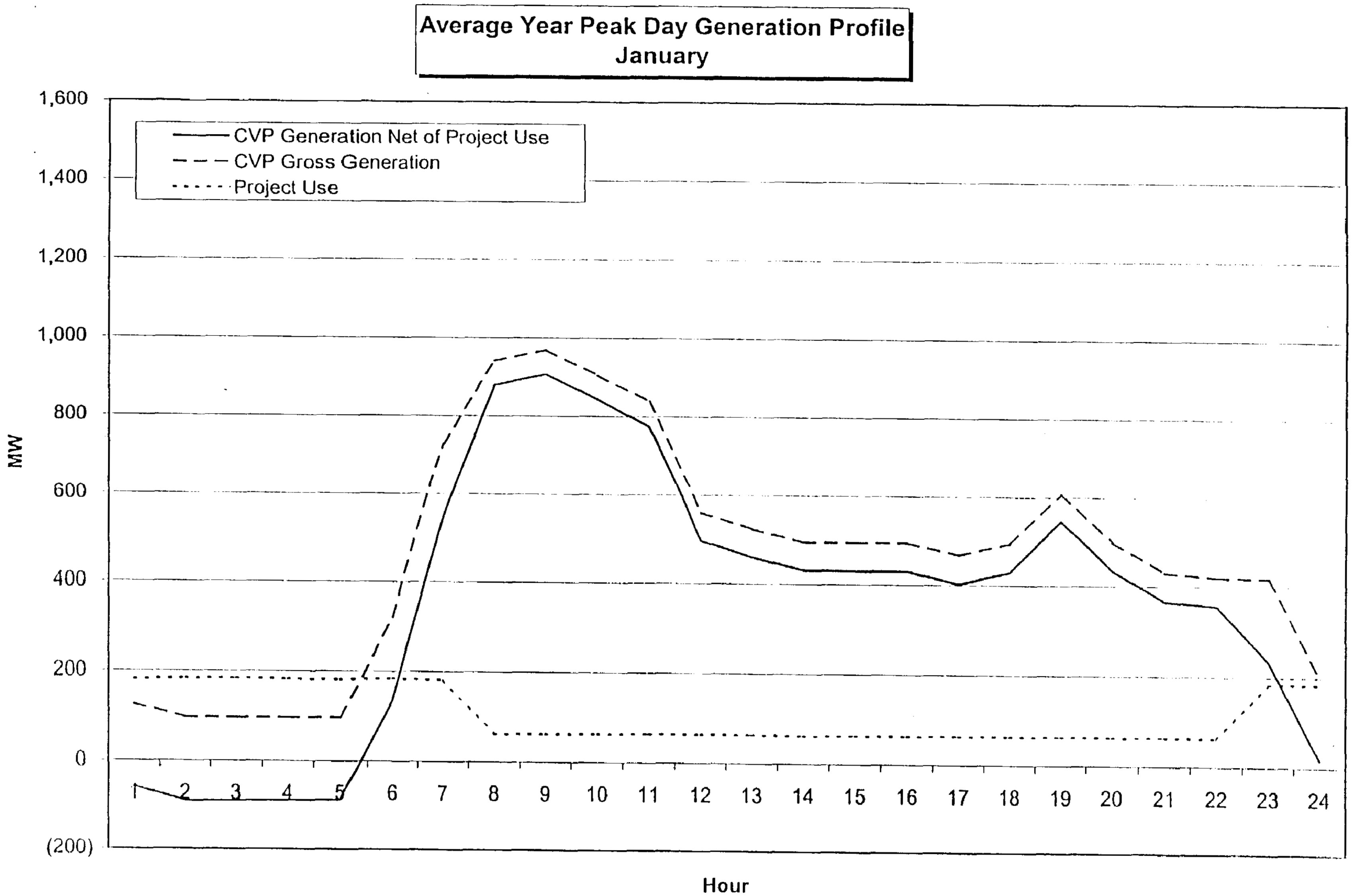

Average Year Peak Day Generation Profile
January
CVP Generation Net of Project Use
CVP Gross Generation
Project Use
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Hour

Fig. 4-2

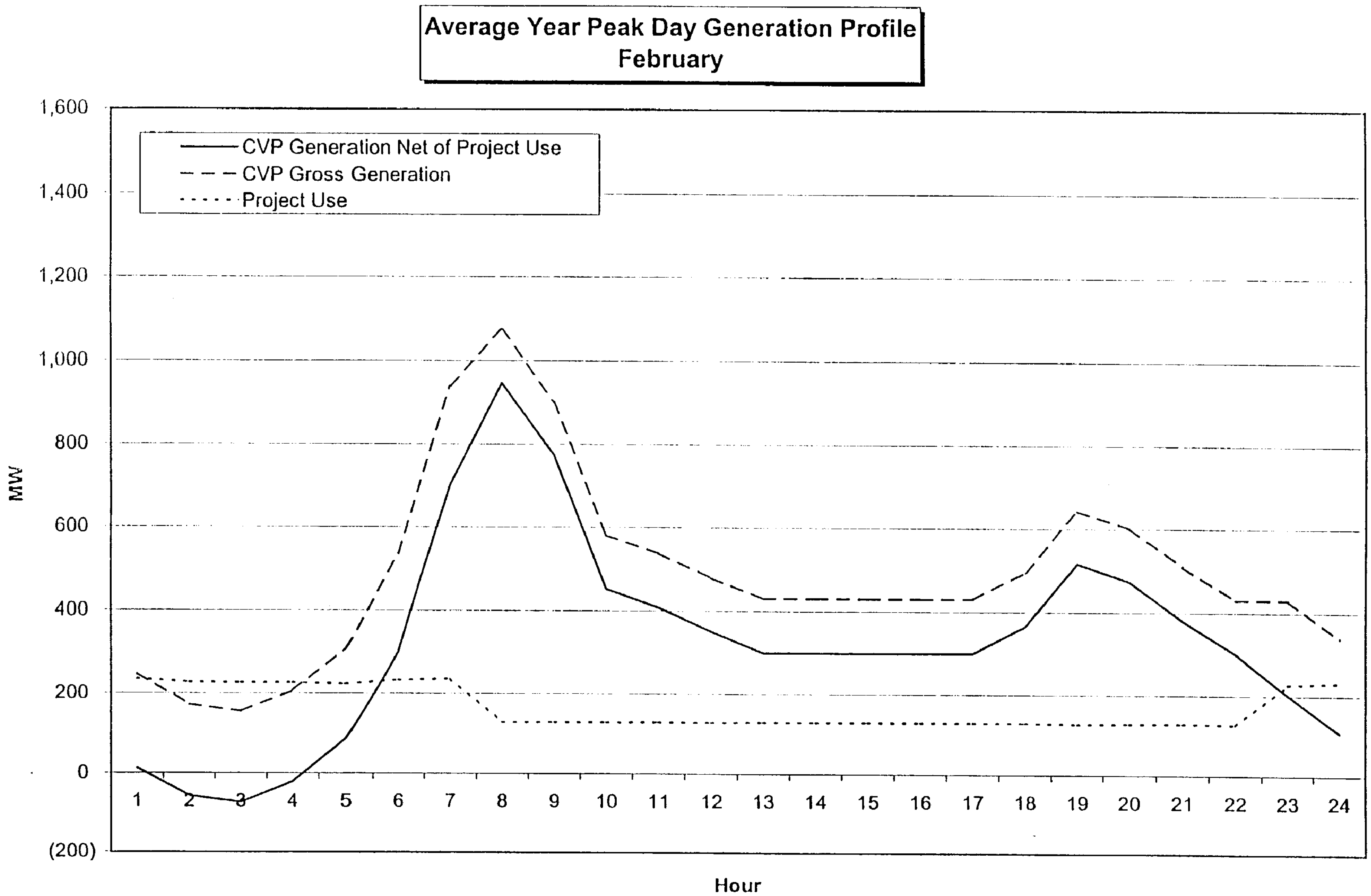

Average Year Peak Day Generation Profile
February
CVP Generation Net of Project Use
CVP Gross Generation
Project Use
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Hour

Fig. 4-3

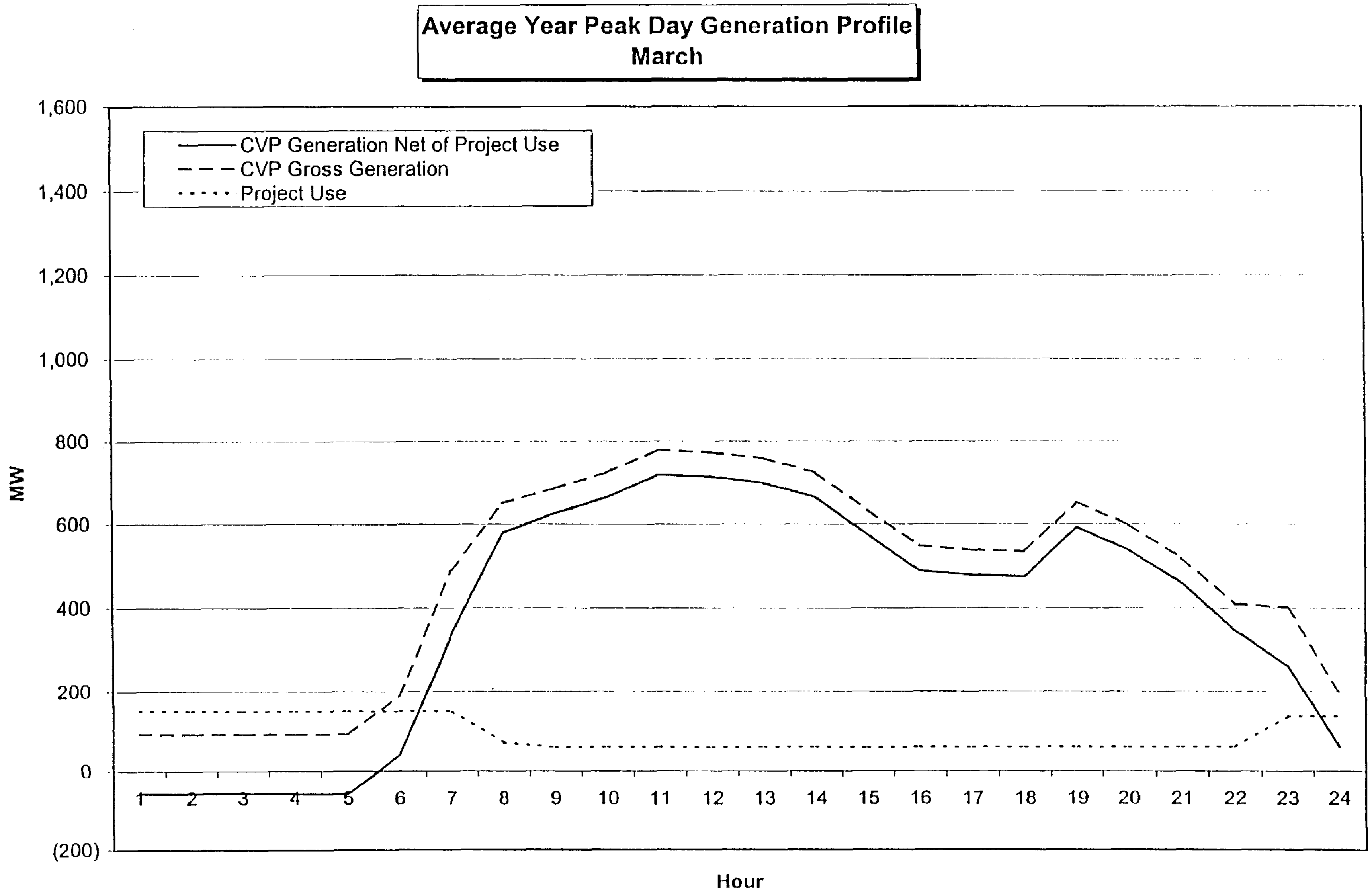
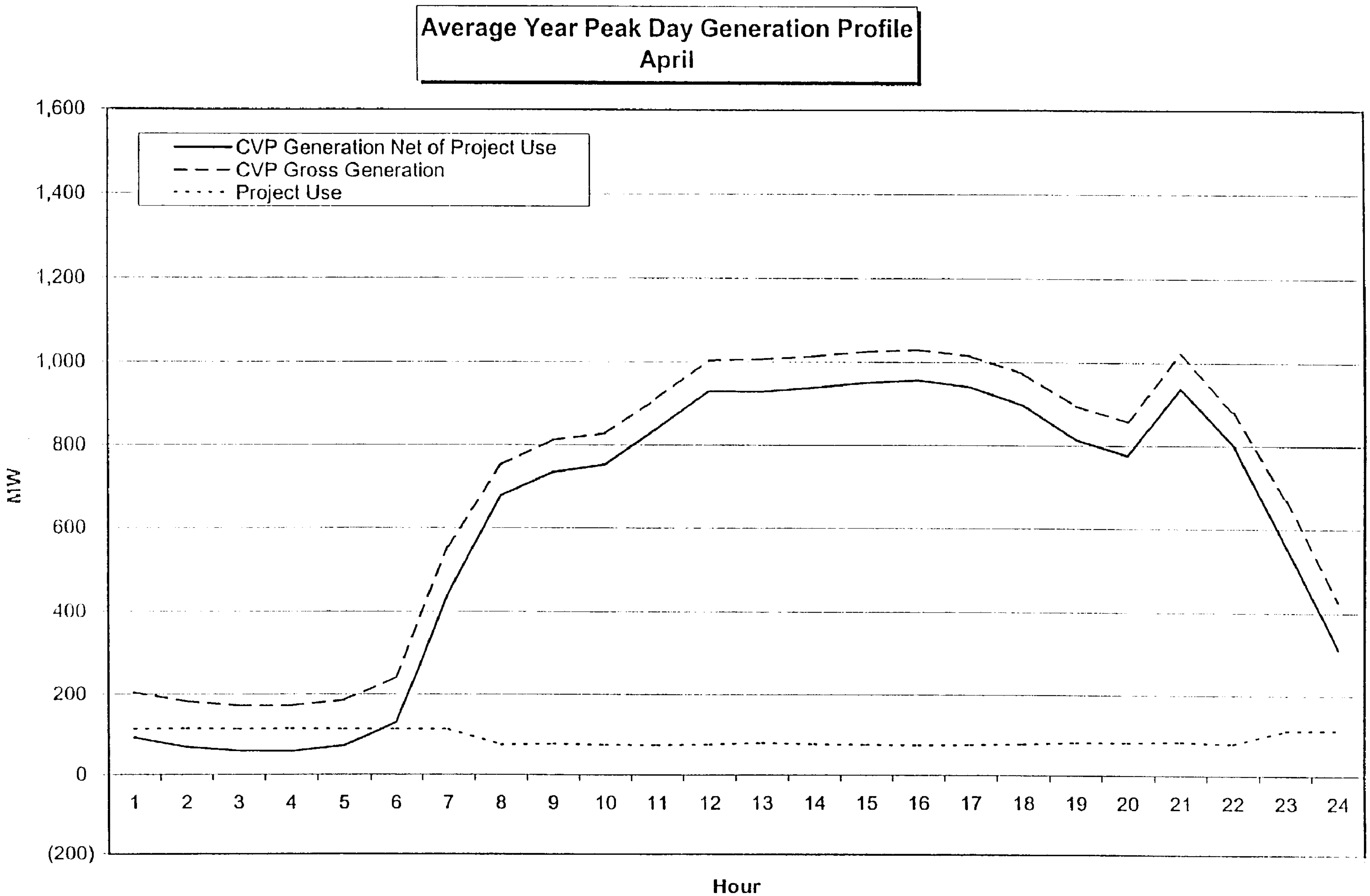

Average Year Peak Day Generation Profile
March
CVP Generation Net of Project Use
CVP Gross Generation
Project Use
MW
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

Fig. 4-4



Average Year Peak Day Generation Profile
April
CVP Generation Net of Project Use
CVP Gross Generation
Project Use
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Hour

Fig. 4-5

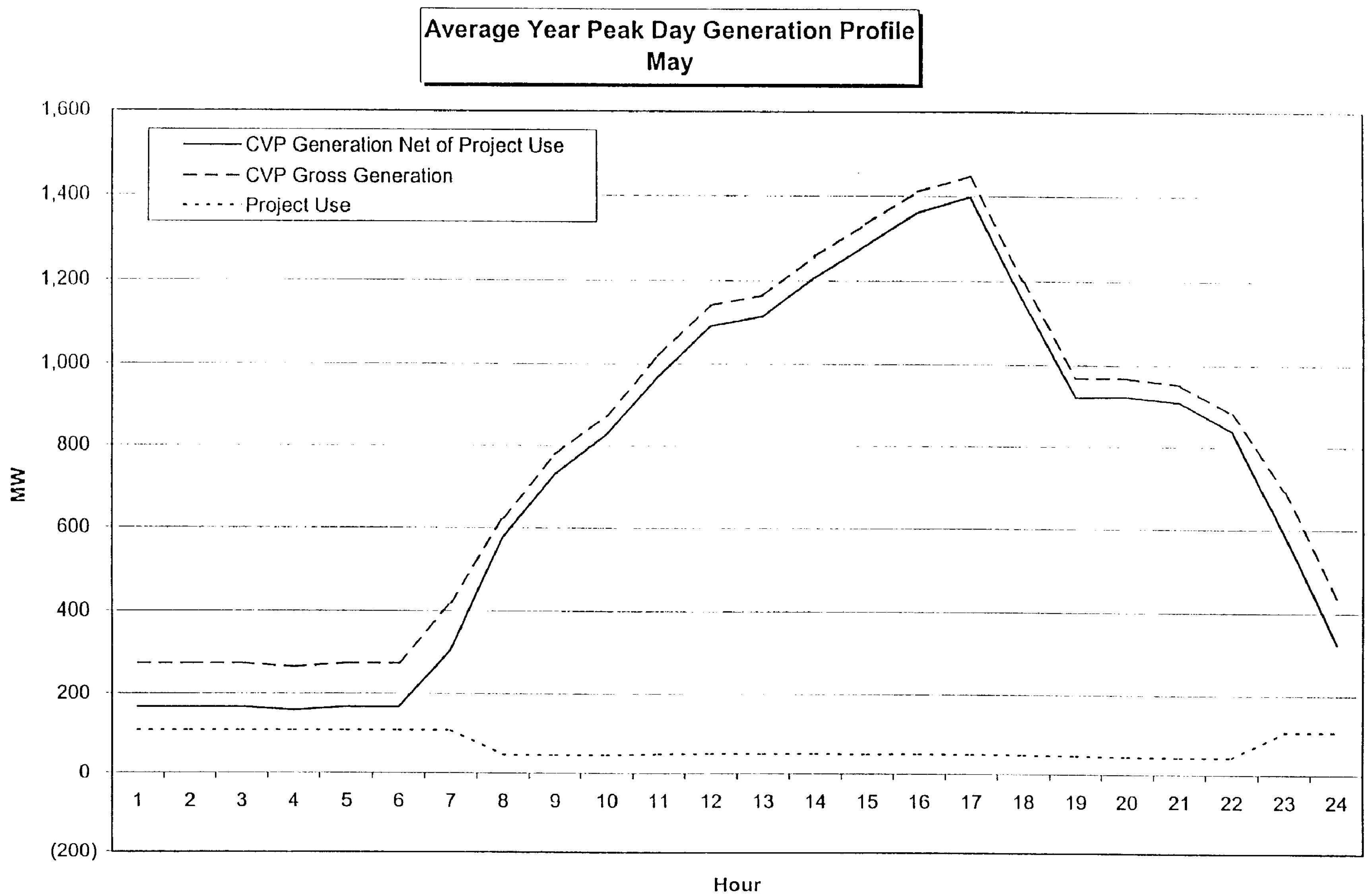

Average Year Peak Day Generation Profile
May
CVP Generation Net of Project Use
CVP Gross Generation
Project Use
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

Fig. 4-6

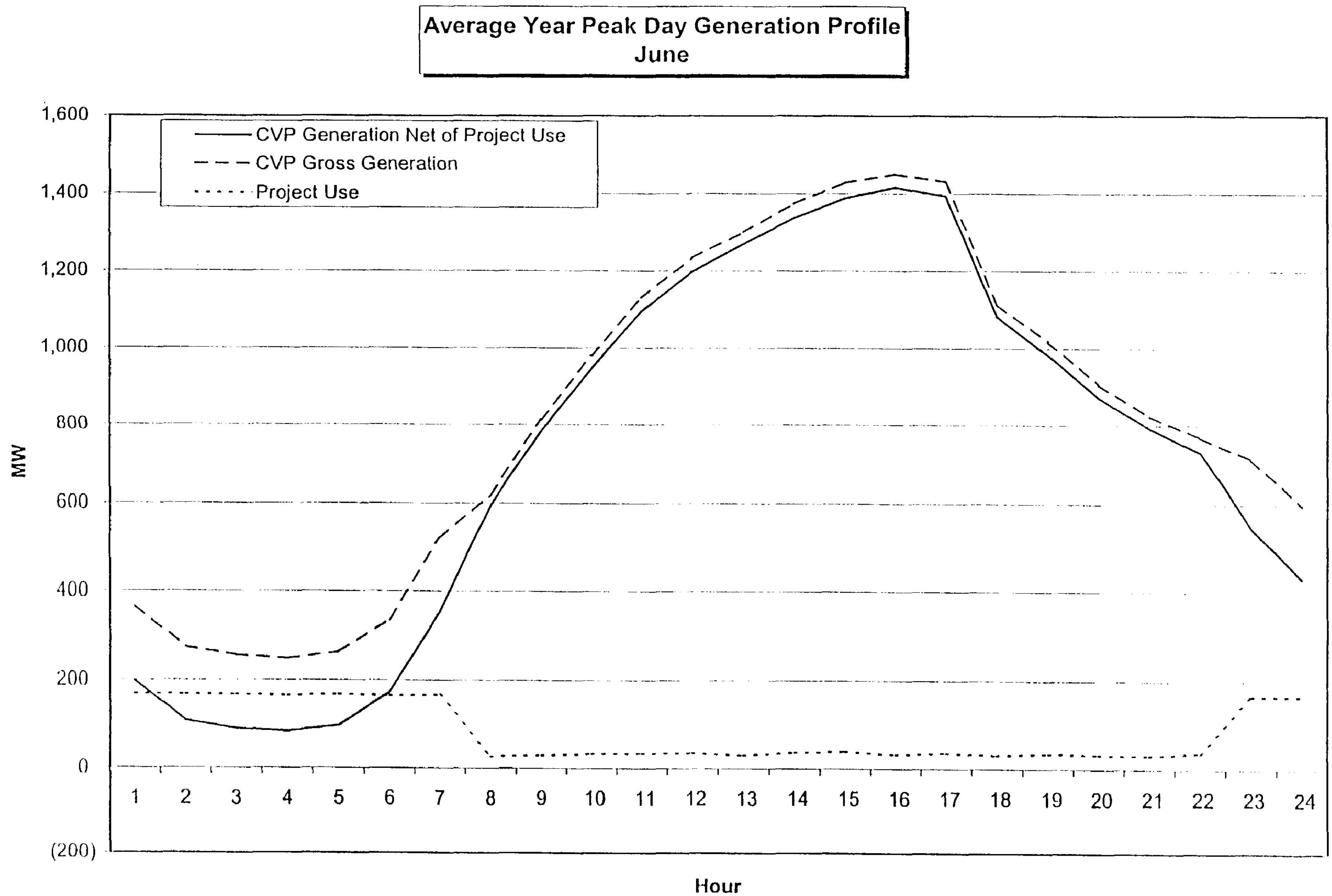

Average Year Peak Day Generation Profile
June
CVP Generation Net of Project Use
CVP Gross Generation
Project Use
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

Fig. 4-7

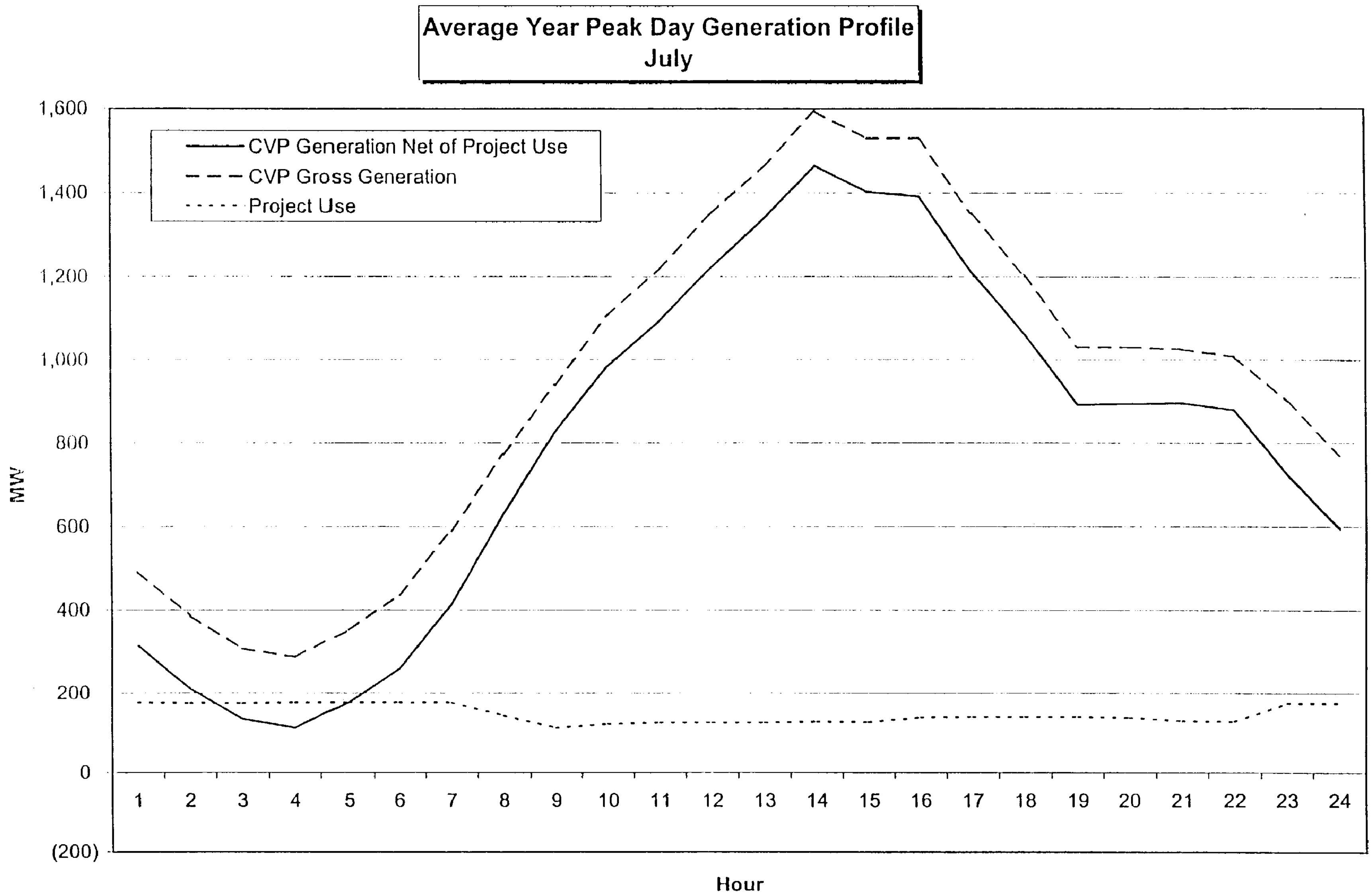

Average Year Peak Day Generation Profile
July
CVP Generation Net of Project Use
CVP Gross Generation
Project Use
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

Fig. 4-8

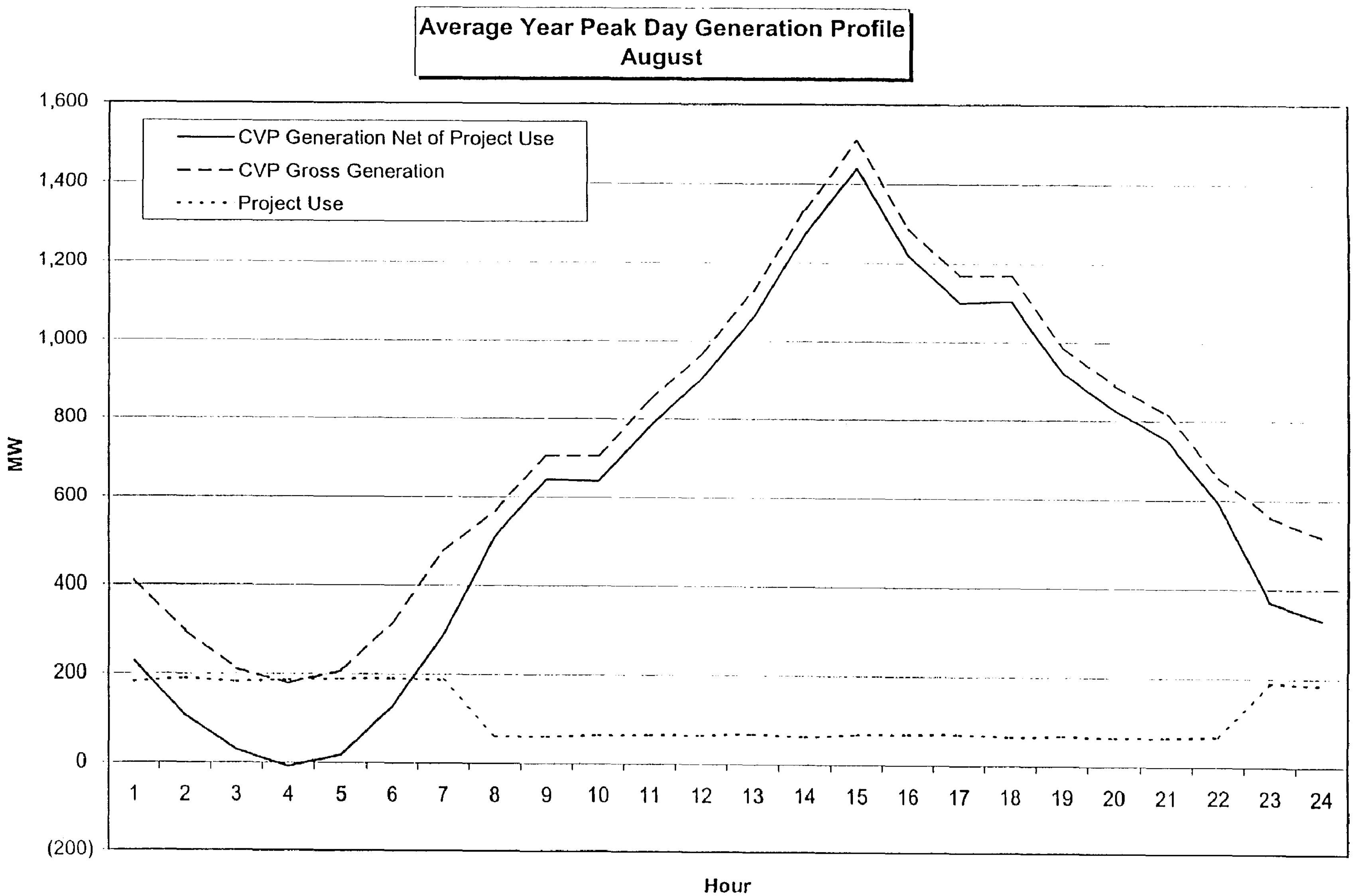

Average Year Peak Day Generation Profile
August
CVP Generation Net of Project Use
CVP Gross Generation
Project Use
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Hour

Fig. 4-9

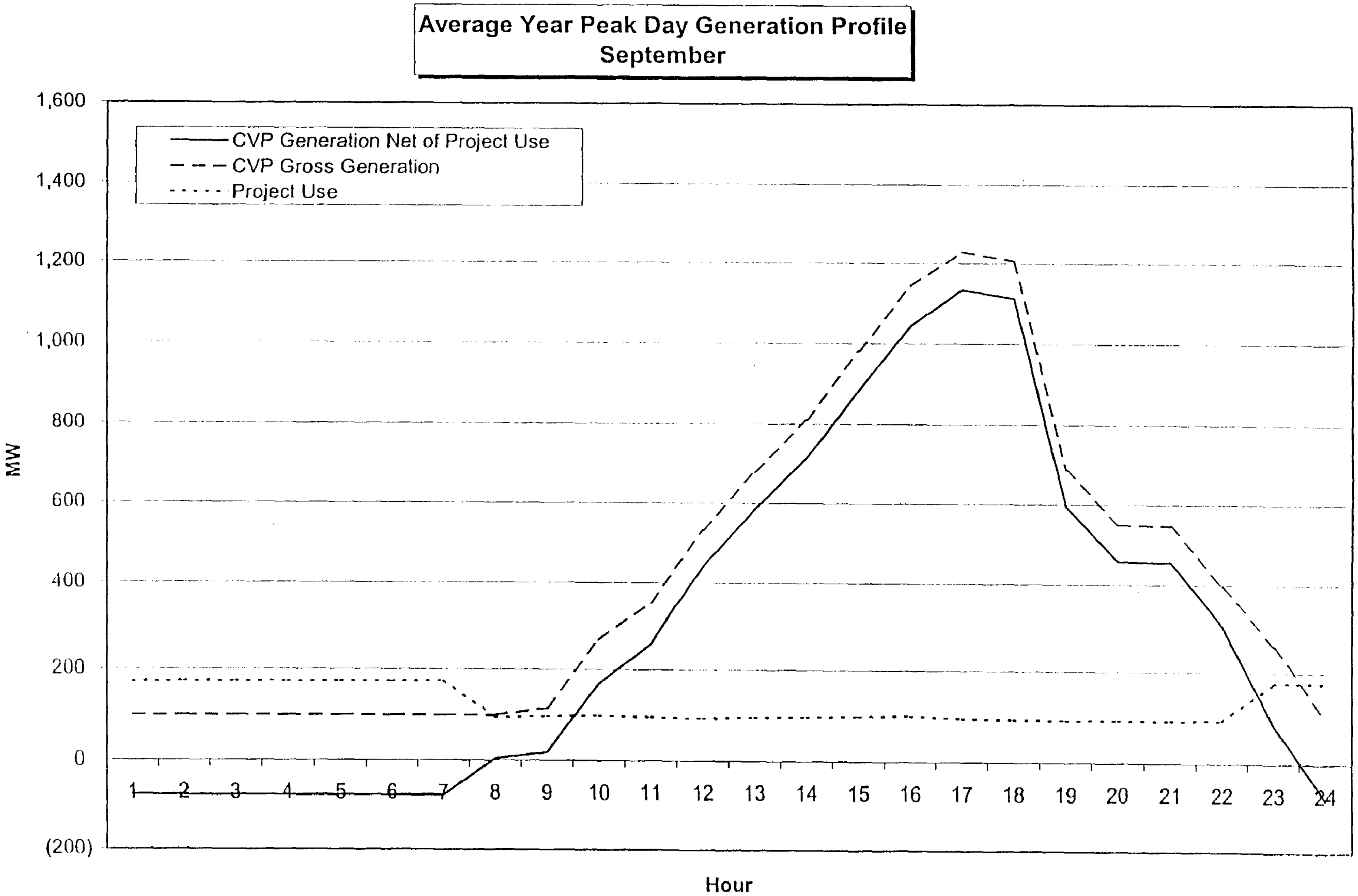

Average Year Peak Day Generation Profile
September
CVP Generation Net of Project Use
CVP Gross Generation
Project Use
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

Fig. 4-10

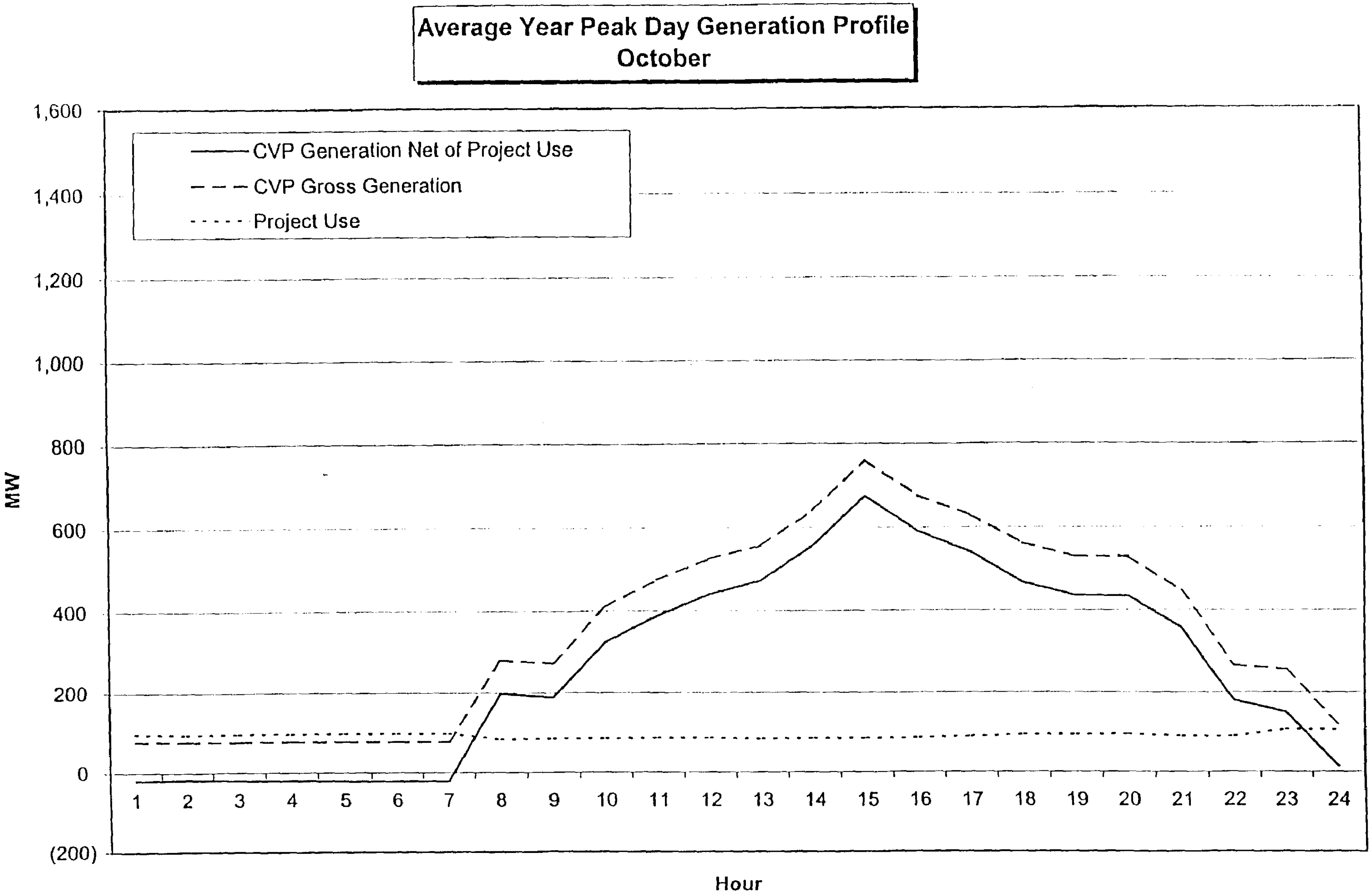

Average Year Peak Day Generation Profile
October
CVP Generation Net of Project Use
CVP Gross Generation
Project Use
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

Fig. 4-11

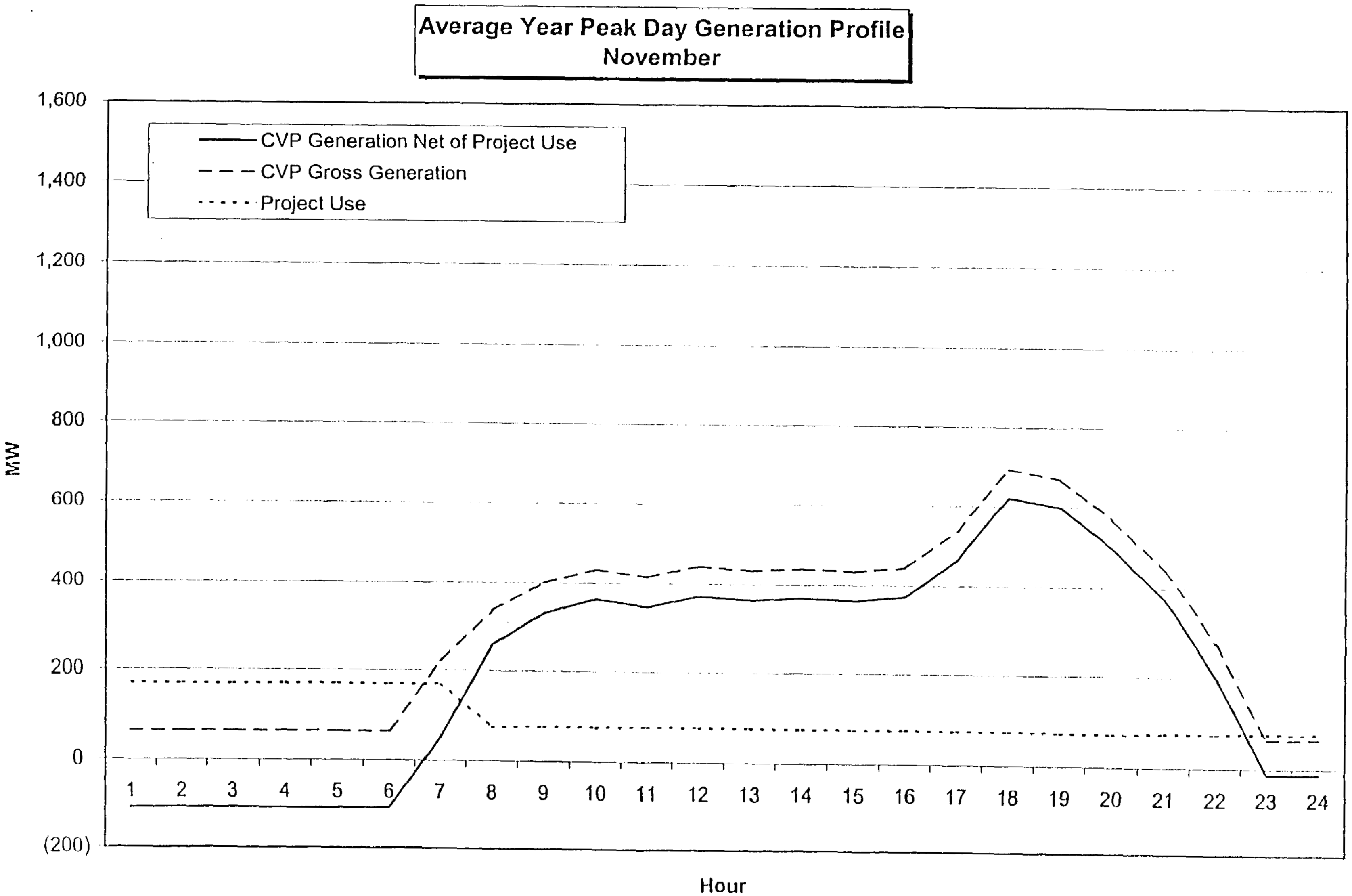
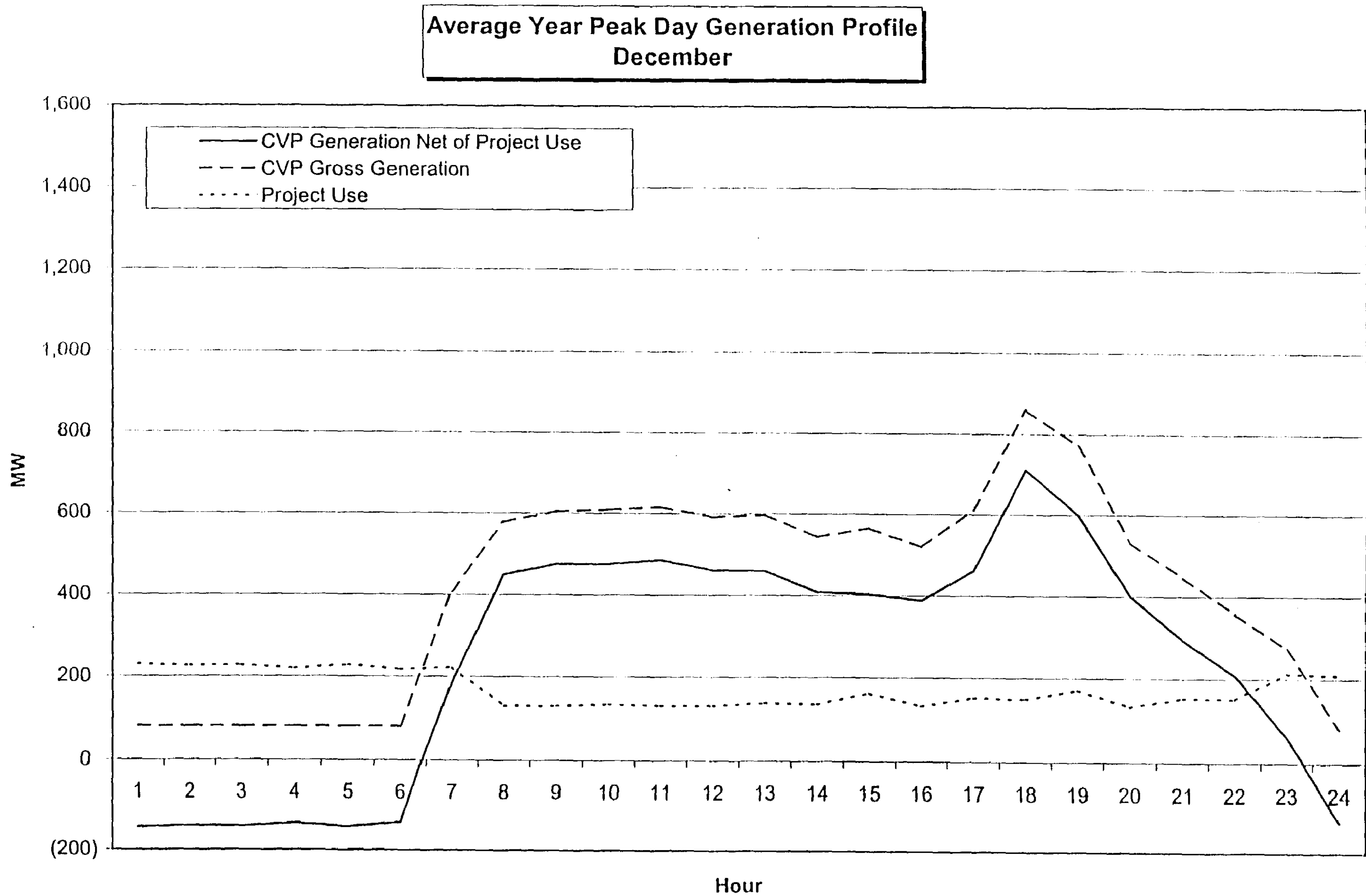

Average Year Peak Day Generation Profile
November
CVP Generation Net of Project Use
CVP Gross Generation
Project Use
MW
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

Fig. 4-12


Average Year Peak Day Generation Profile
December
CVP Generation Net of Project Use
CVP Gross Generation
Project Use
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

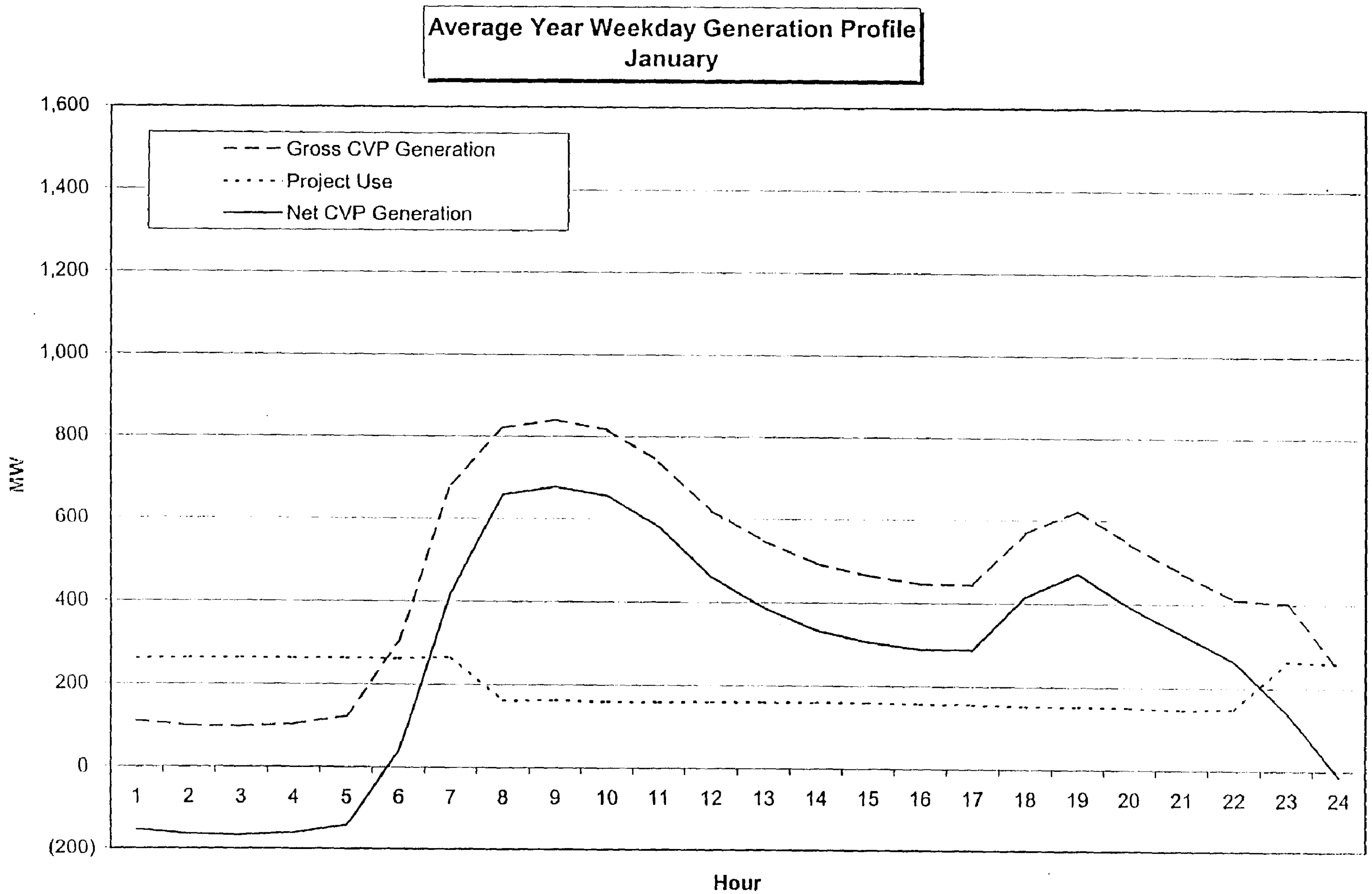
Daily Generation Profile

Average Generation

Average Weekday

Figures 5-1 thru 5-12

Fig. 5-1



Average Year Weekday Generation Profile
January
Gross CVP Generation
Project Use
Net CVP Generation
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

Fig. 5-2

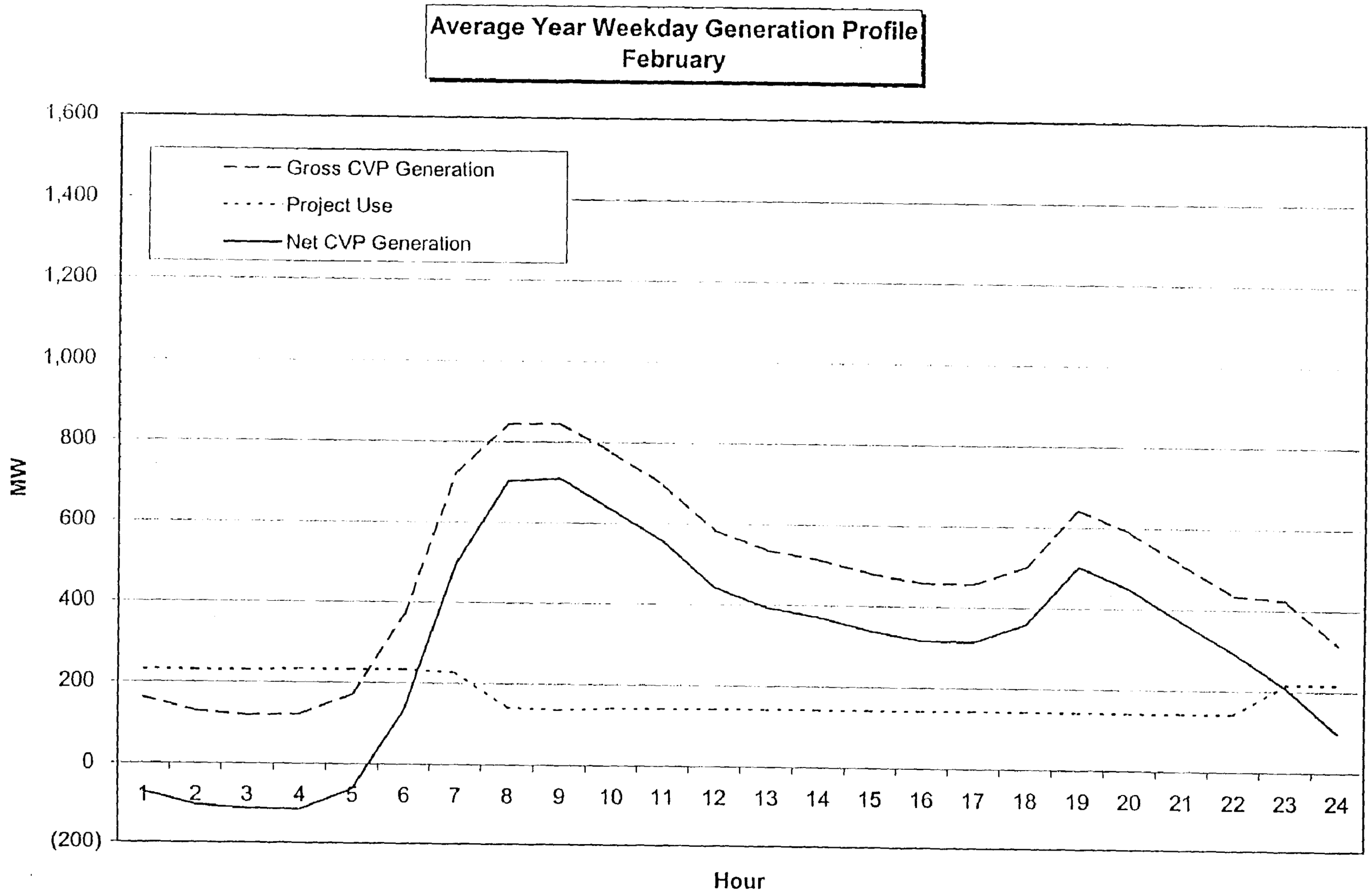
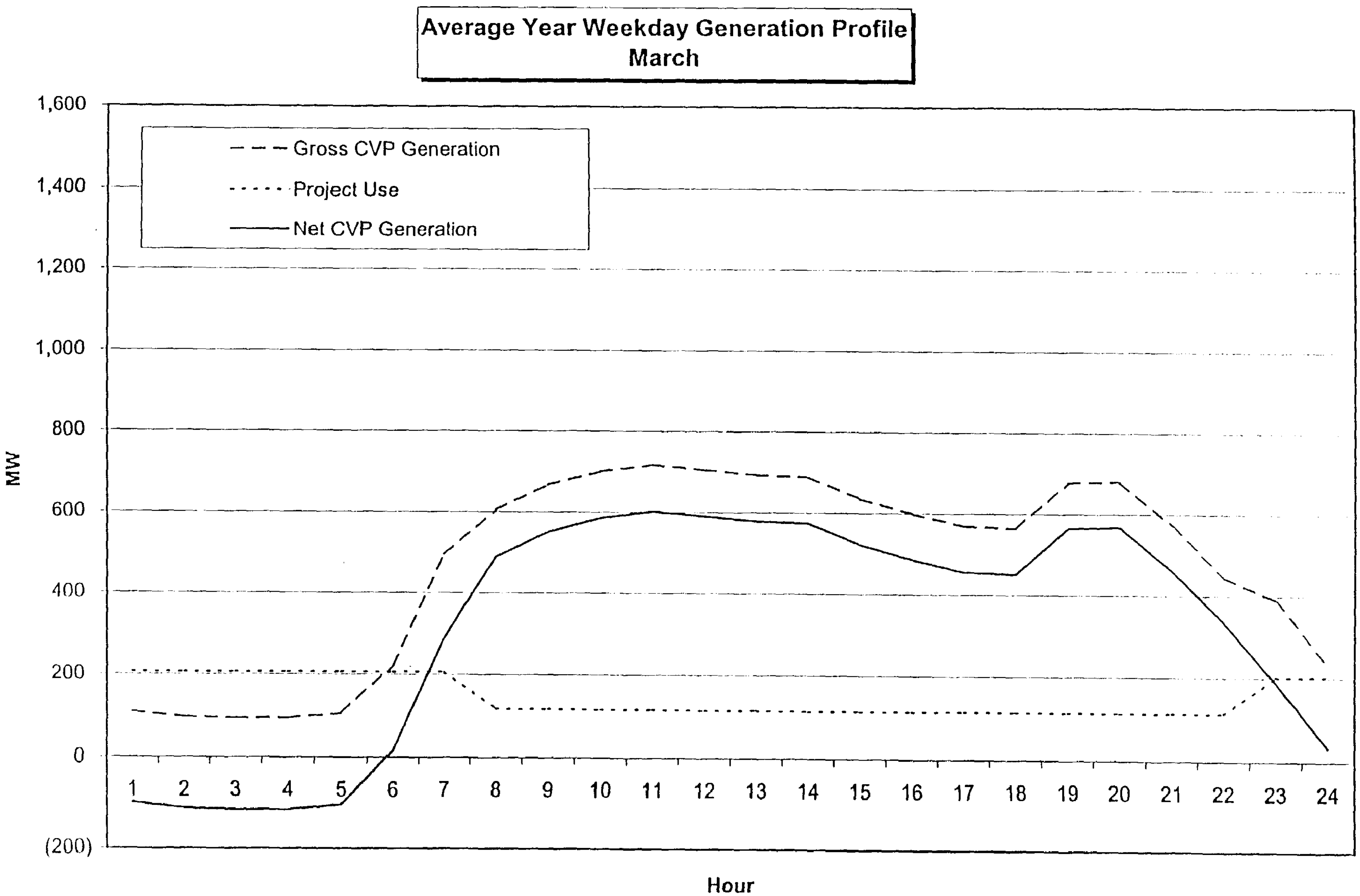

Average Year Weekday Generation Profile
February
Gross CVP Generation
Project Use
Net CVP Generation
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

Fig. 5-3



Average Year Weekday Generation Profile
March
Gross CVP Generation
Project Use
Net CVP Generation
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

Fig. 5-4

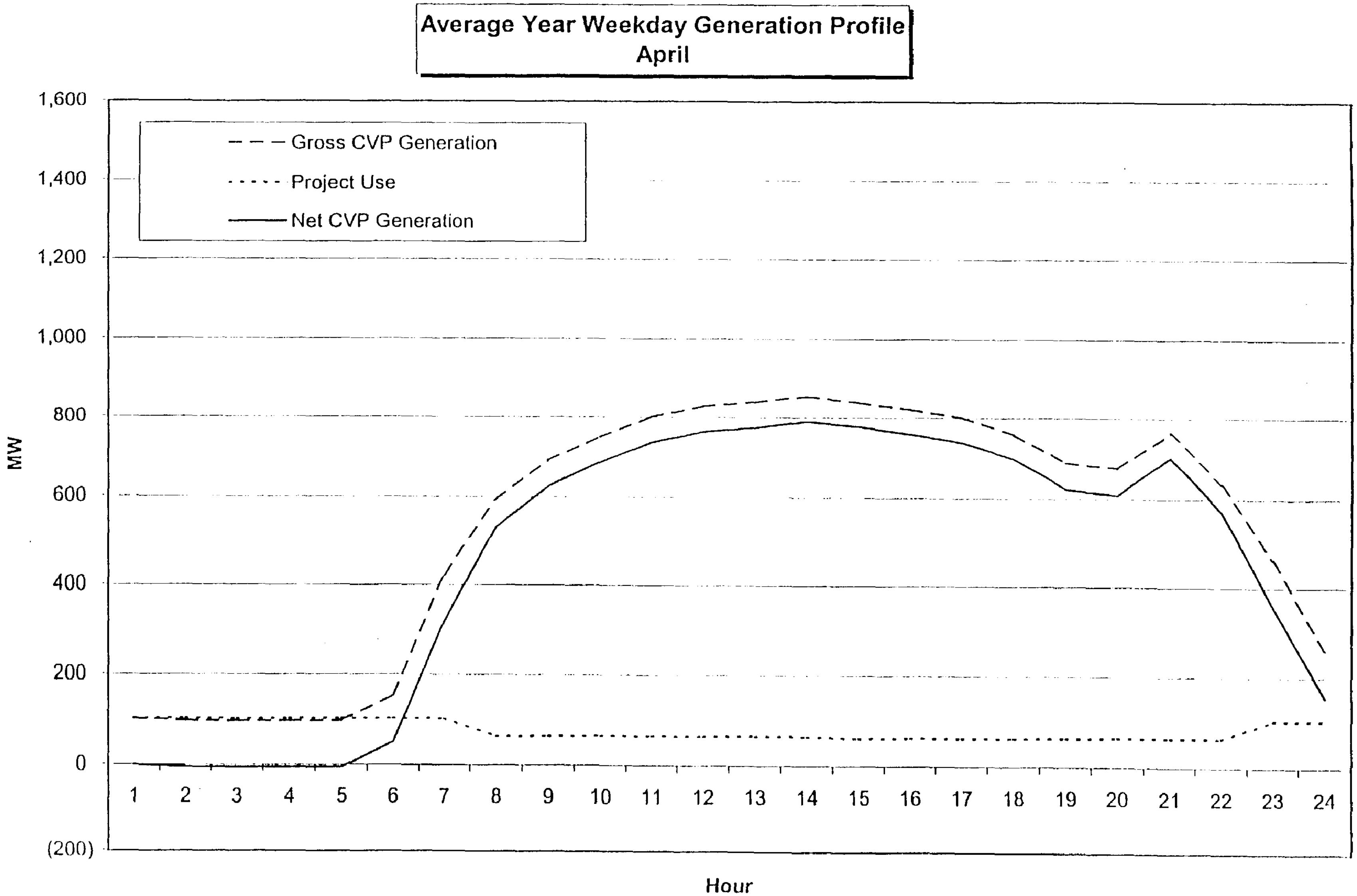

Average Year Weekday Generation Profile
April
Gross CVP Generation
Project Use
Net CVP Generation
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

Fig. 5-5

Average Year Weekday Generation Profile
May

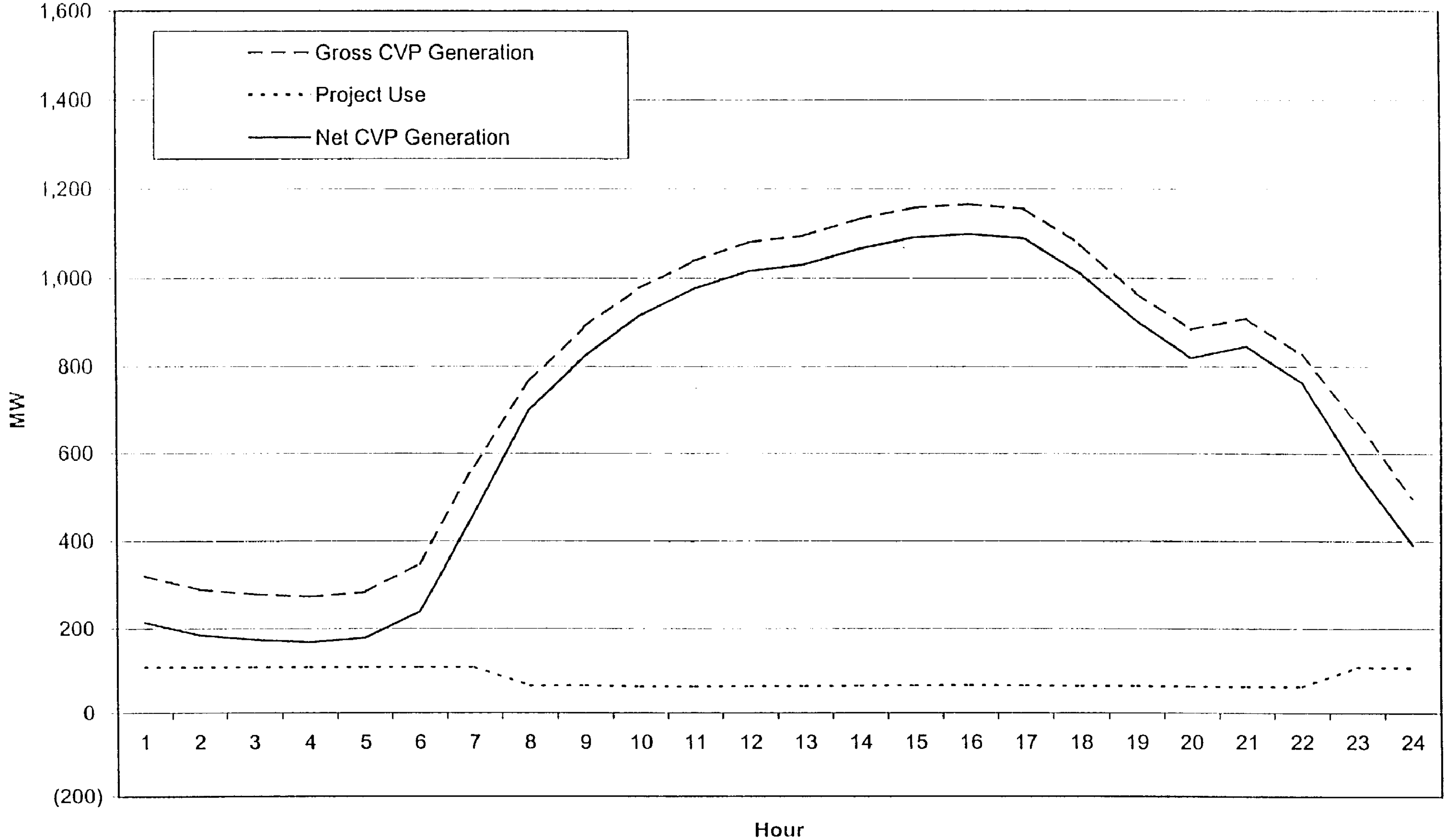
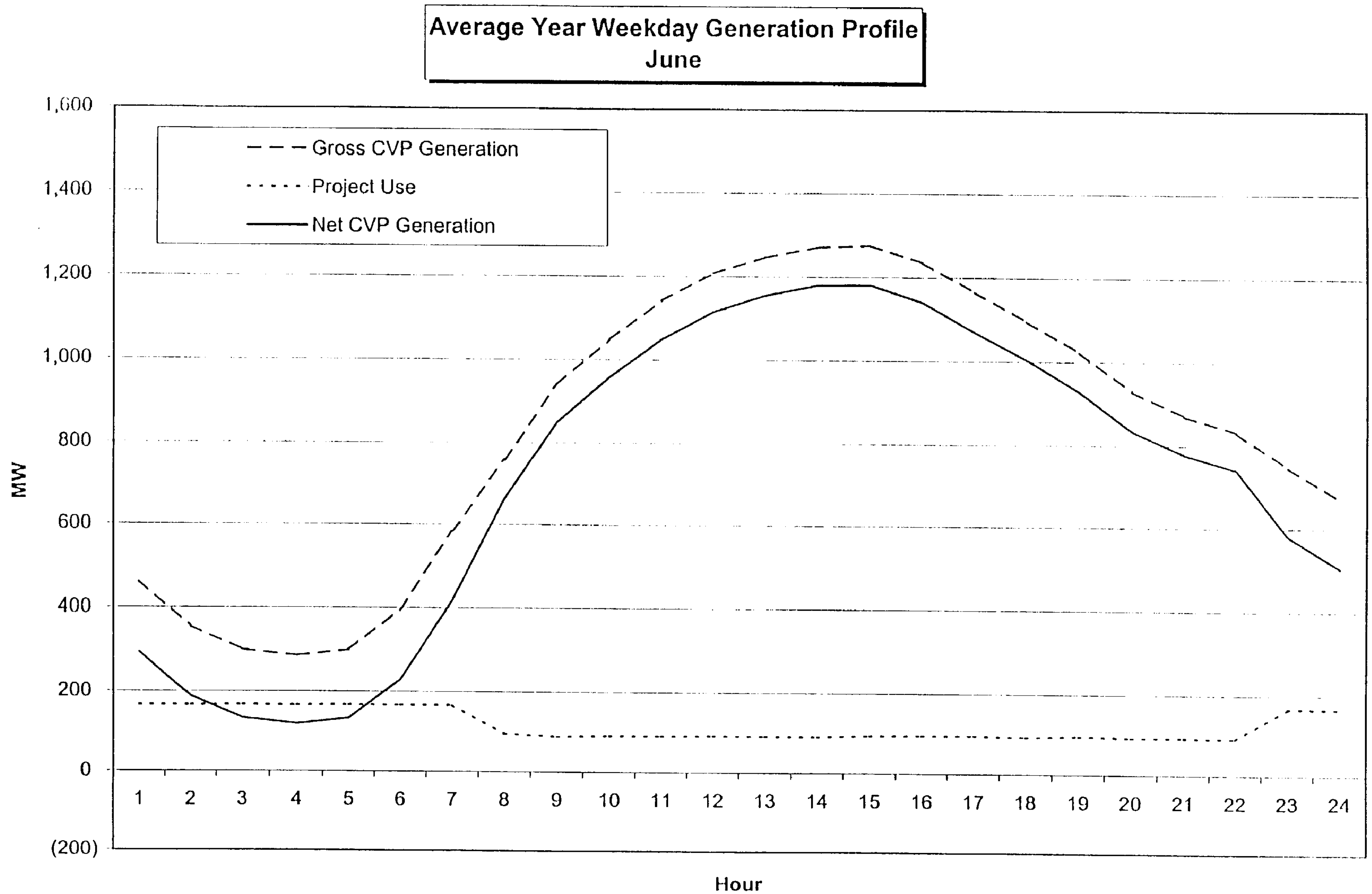


Fig. 5-6



Average Year Weekday Generation Profile
June
Gross CVP Generation
Project Use
Net CVP Generation
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1
2
3
4
5
6
7
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16
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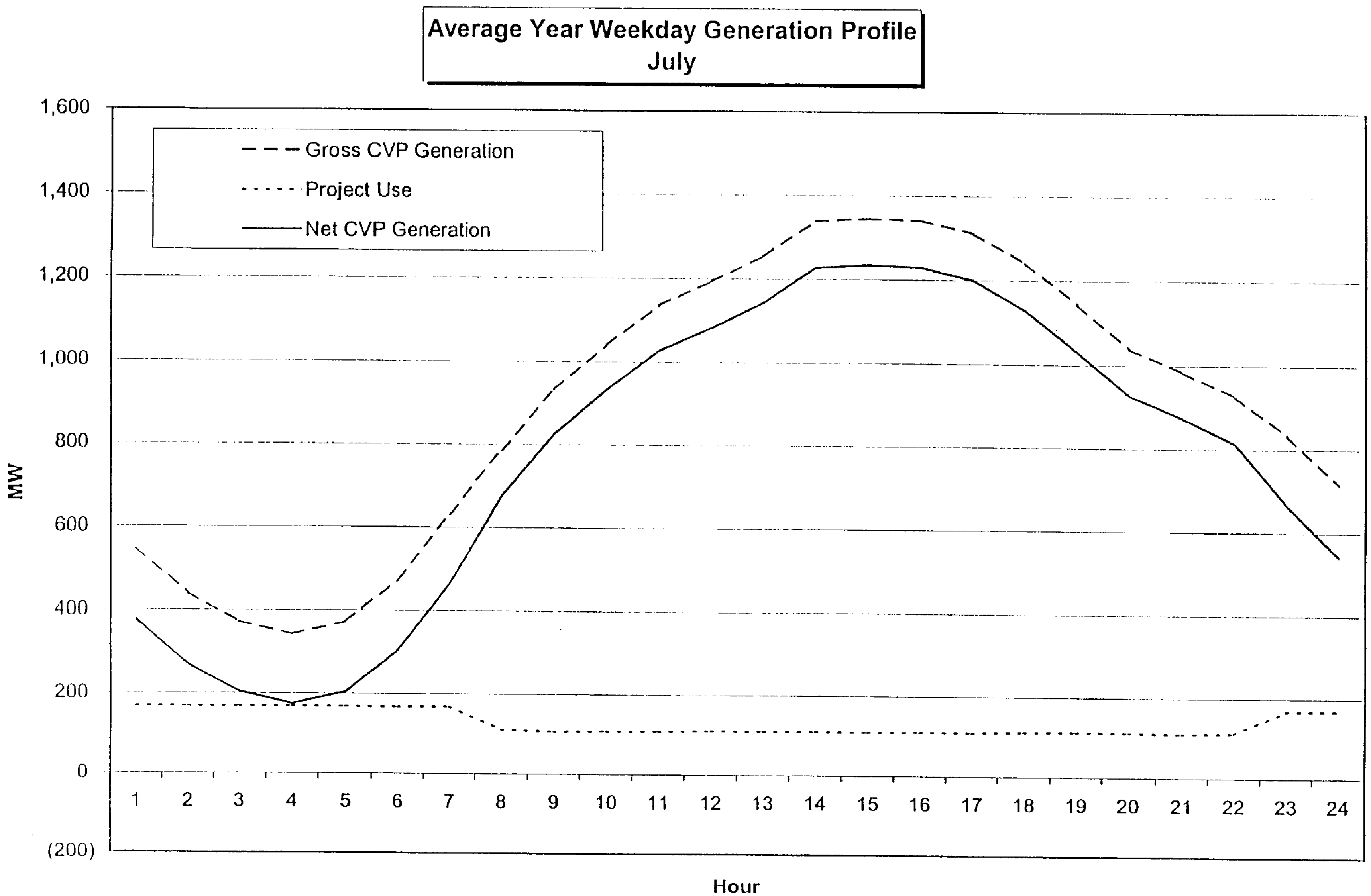
20
21
22
23
24
Hour

Fig. 5-F



Average Year Weekday Generation Profile
July
Gross CVP Generation
Project Use
Net CVP Generation
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1
2
3
4
5
6
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14
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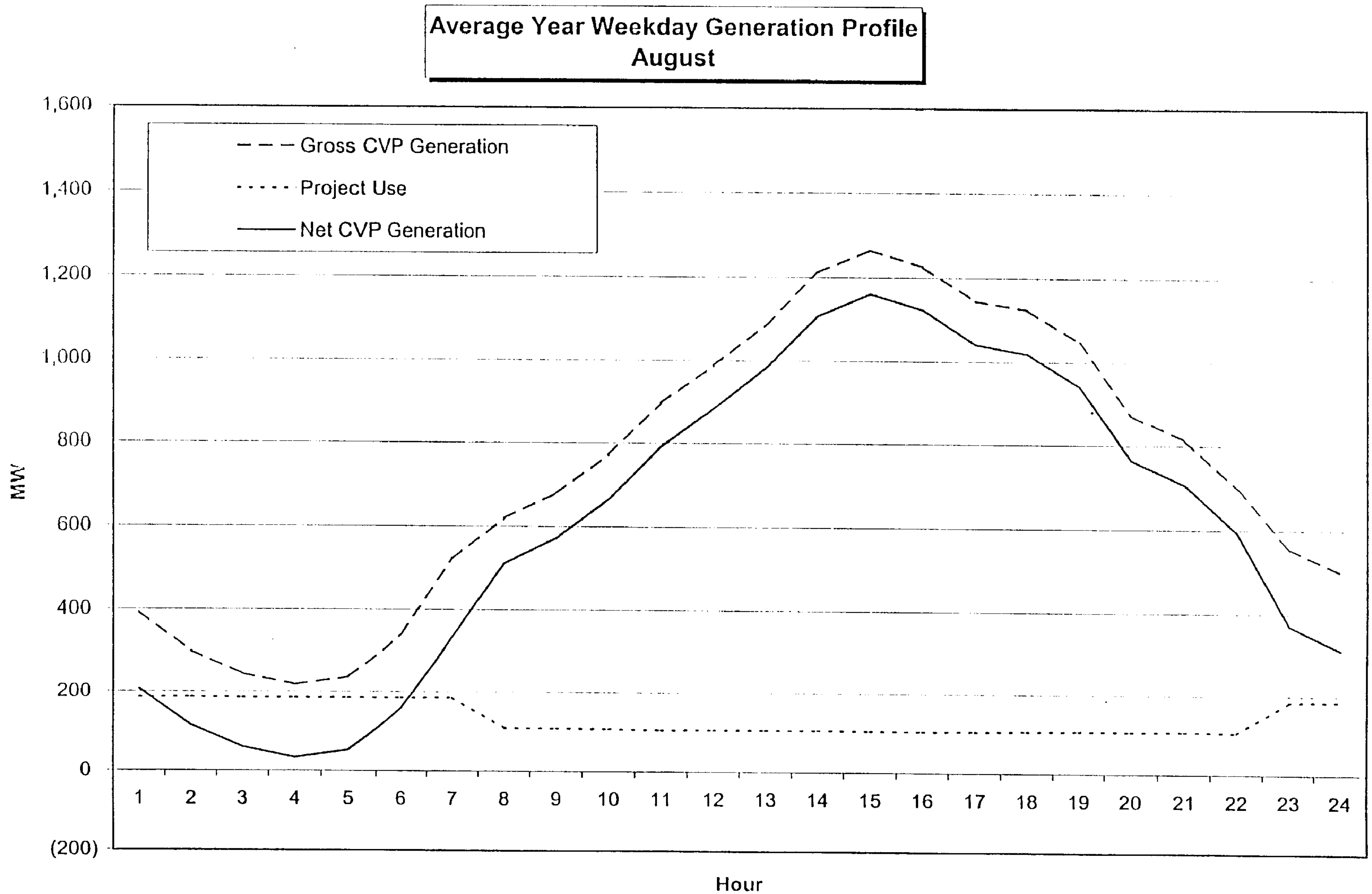
16
17
18
19
20
21
22
23
24
Hour

Fig. 5-8


Average Year Weekday Generation Profile
August
Gross CVP Generation
Project Use
Net CVP Generation
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1
2
3
4
5
6
7
8
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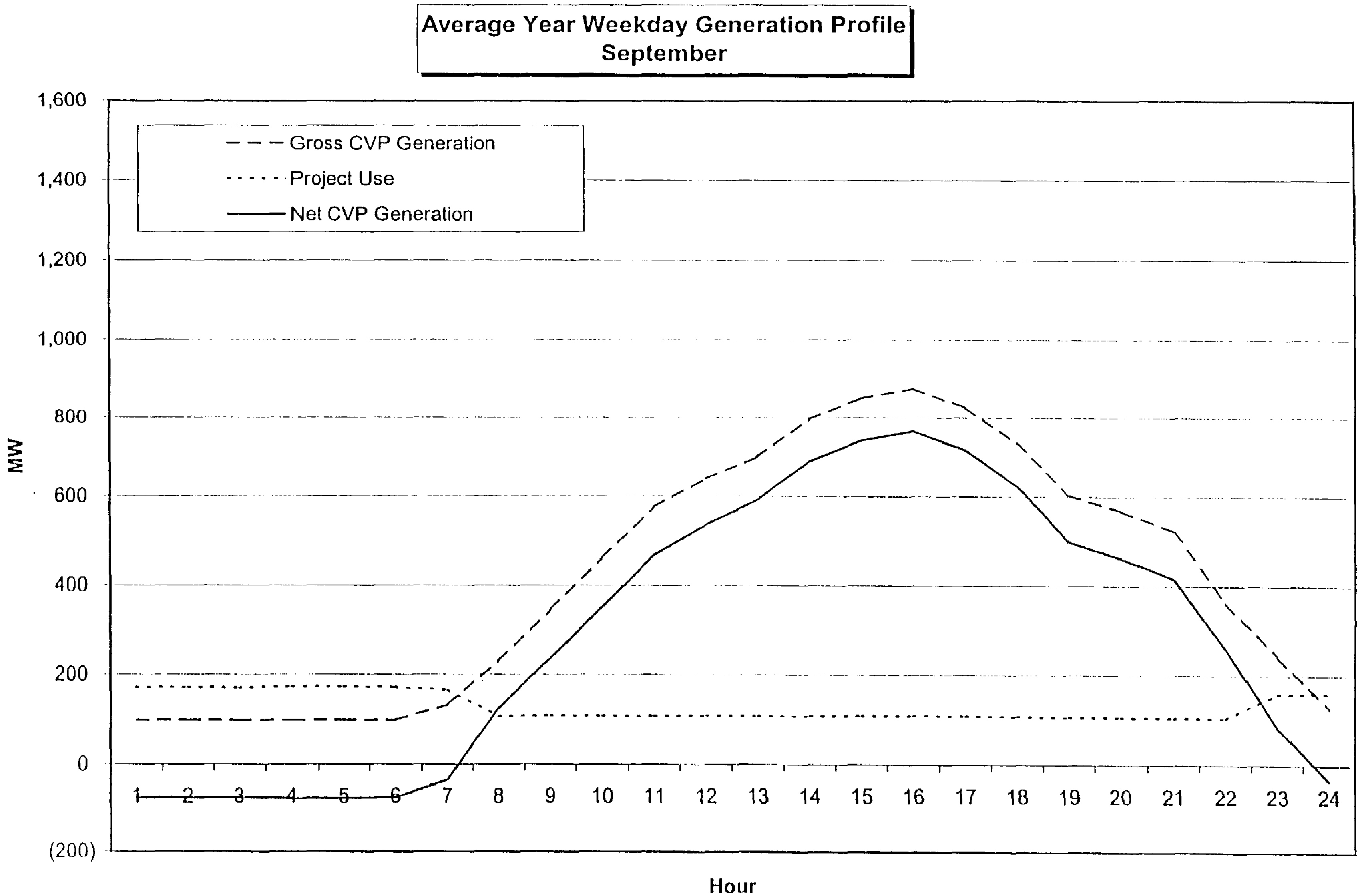
19
20
21
22
23
24
Hour

Fig. 5-9


Average Year Weekday Generation Profile
September
Gross CVP Generation
Project Use
Net CVP Generation
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1
2
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5
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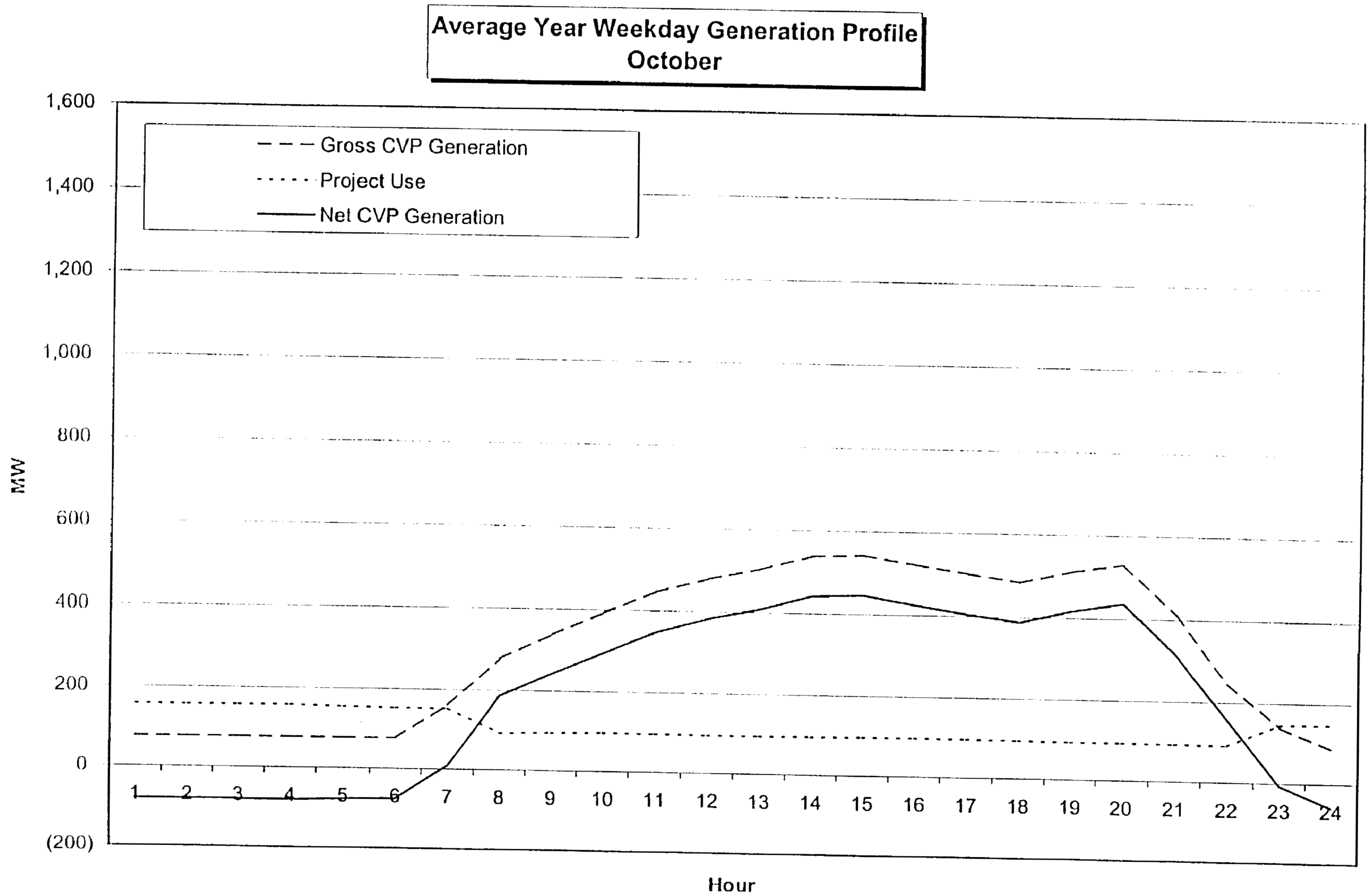
21
22
23
24
Hour

Fig. 5-10


Average Year Weekday Generation Profile
October
Gross CVP Generation
Project Use
Net CVP Generation
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1
2
3
4
5
6
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21
22
23
24
Hour

Fig. 5-11

Average Year Weekday Generation Profile
November

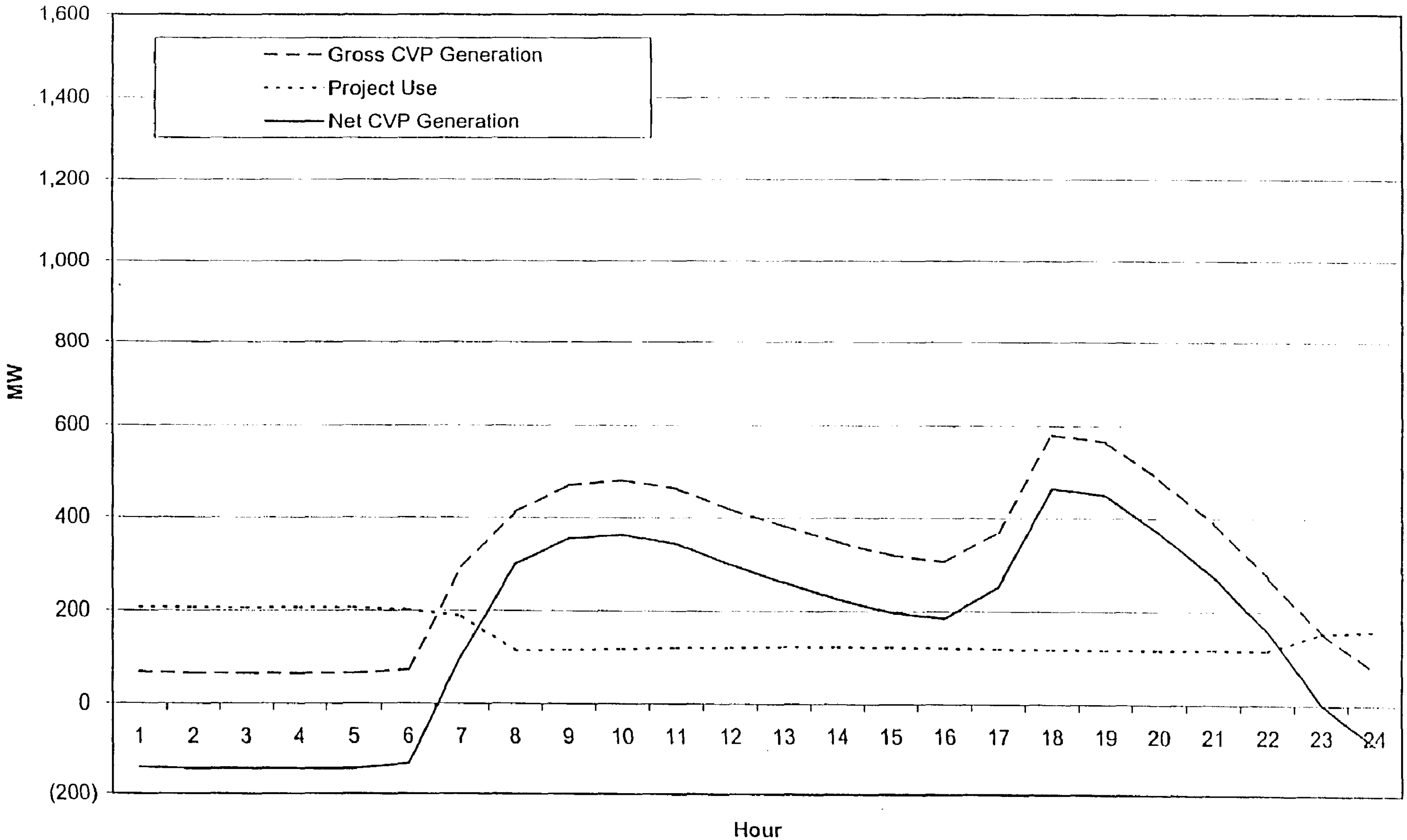
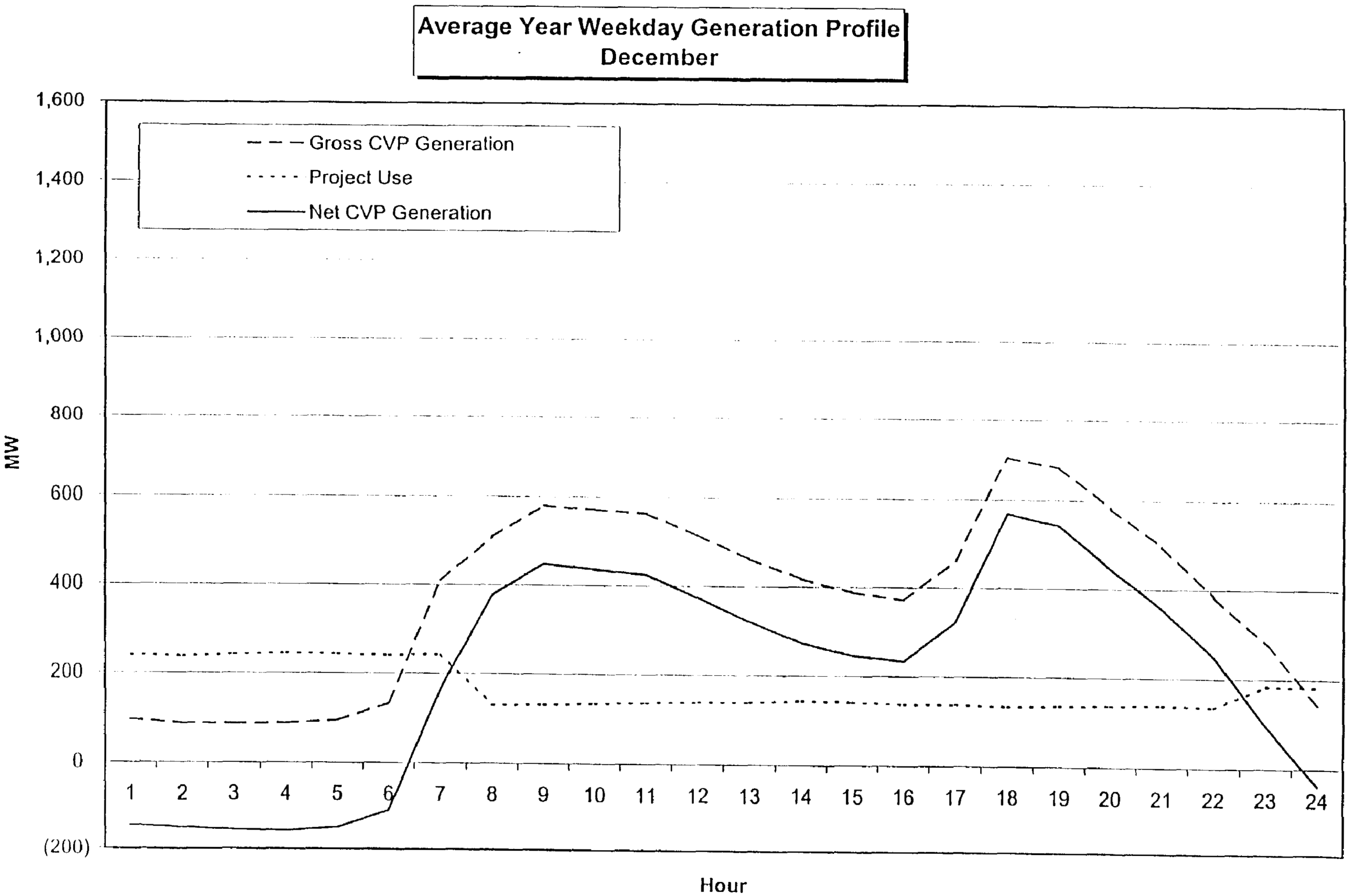


Fig. 5-12



Average Year Weekday Generation Profile
December
Gross CVP Generation
Project Use
Net CVP Generation
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1
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16
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20
21
22
23
24
Hour

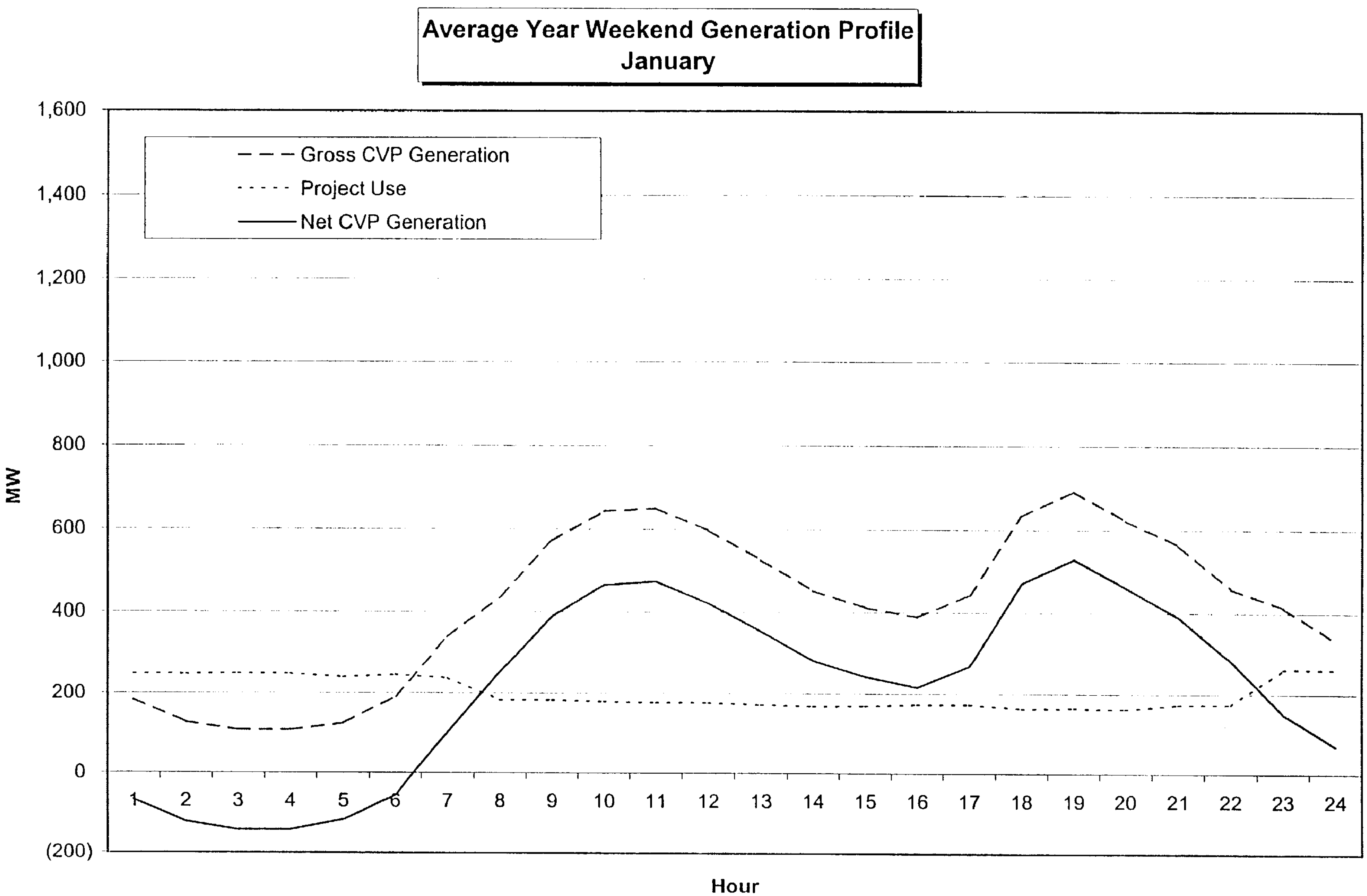
Daily Generation Profile

Average Generation

Average Weekend

Figures 6-1 thru 6-12

Fig. 6-1


Average Year Weekend Generation Profile
January
Gross CVP Generation
Project Use
Net CVP Generation
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1
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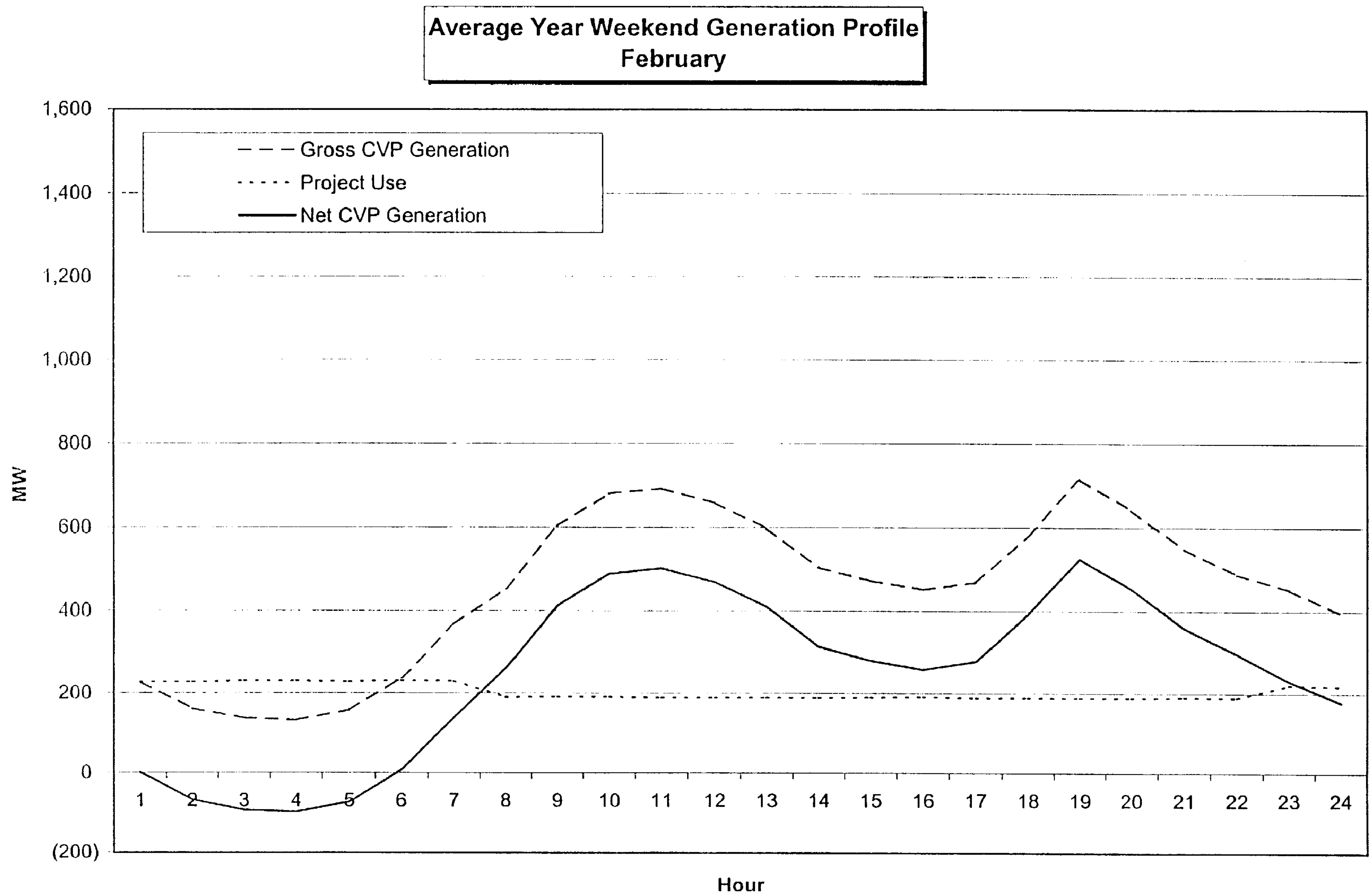
14
15
16
17
18
19
20
21
22
23
24
Hour

Fig. 6-2



Average Year Weekend Generation Profile
February
Gross CVP Generation
Project Use
Net CVP Generation
MW
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
1
2
3
4
5
6
7
8
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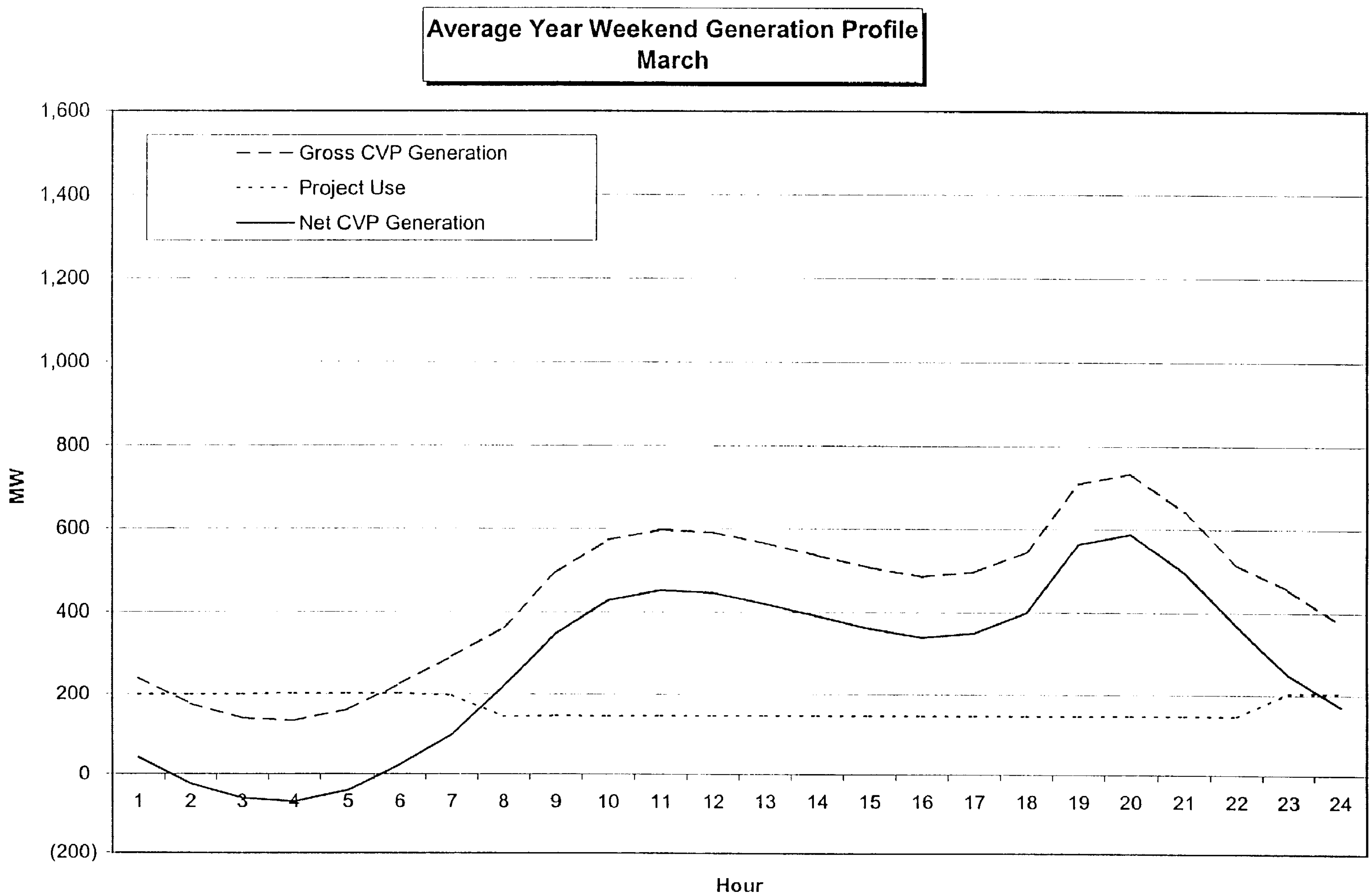
16
17
18
19
20
21
22
23
24
Hour

Fig. 6-3



Average Year Weekend Generation Profile
March
Gross CVP Generation
Project Use
Net CVP Generation
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1
2
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16
17
18
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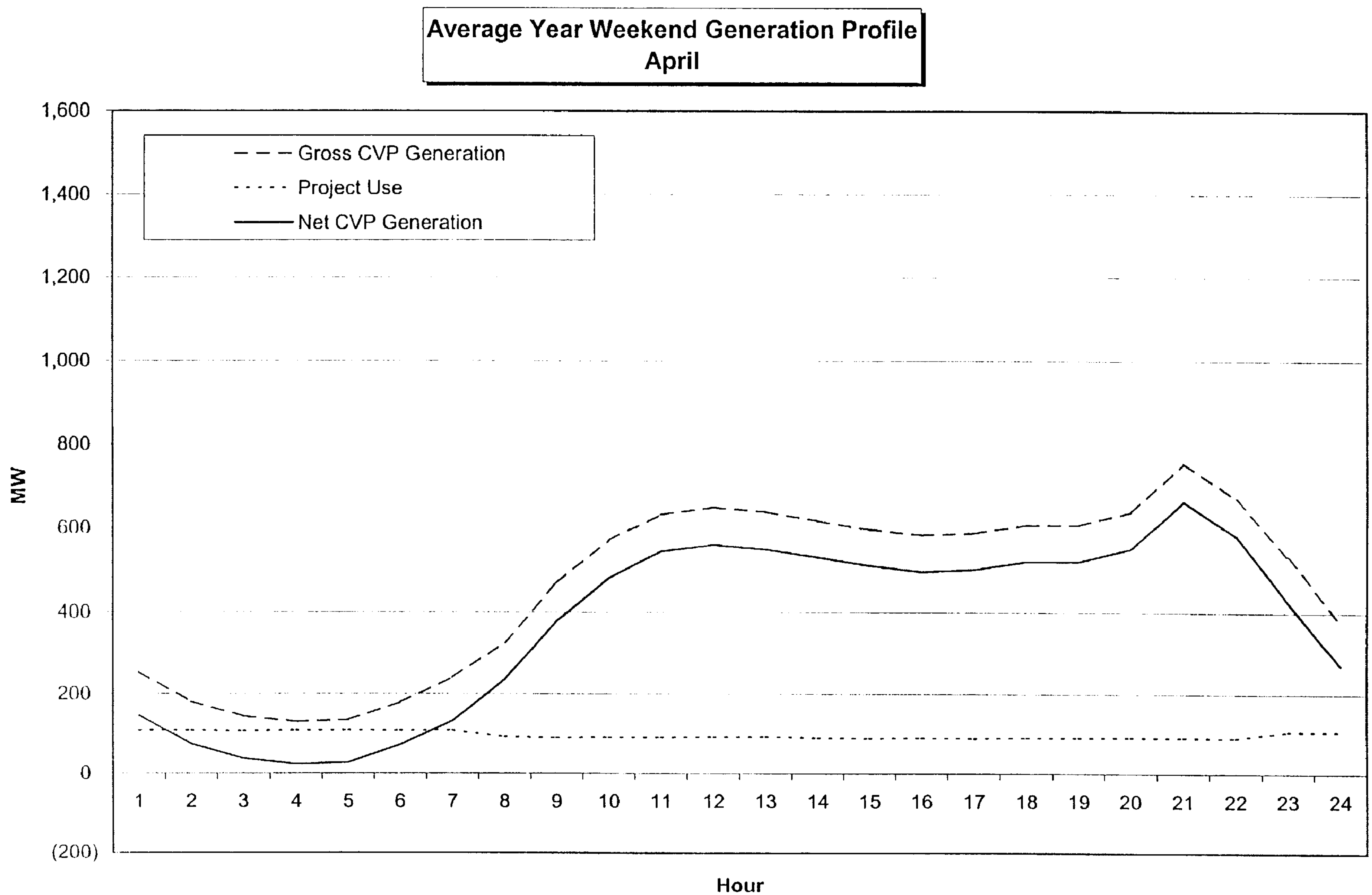
20
21
22
23
24
Hour

Fig. 6-4


Average Year Weekend Generation Profile
April
Gross CVP Generation
Project Use
Net CVP Generation
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1
2
3
4
5
6
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14
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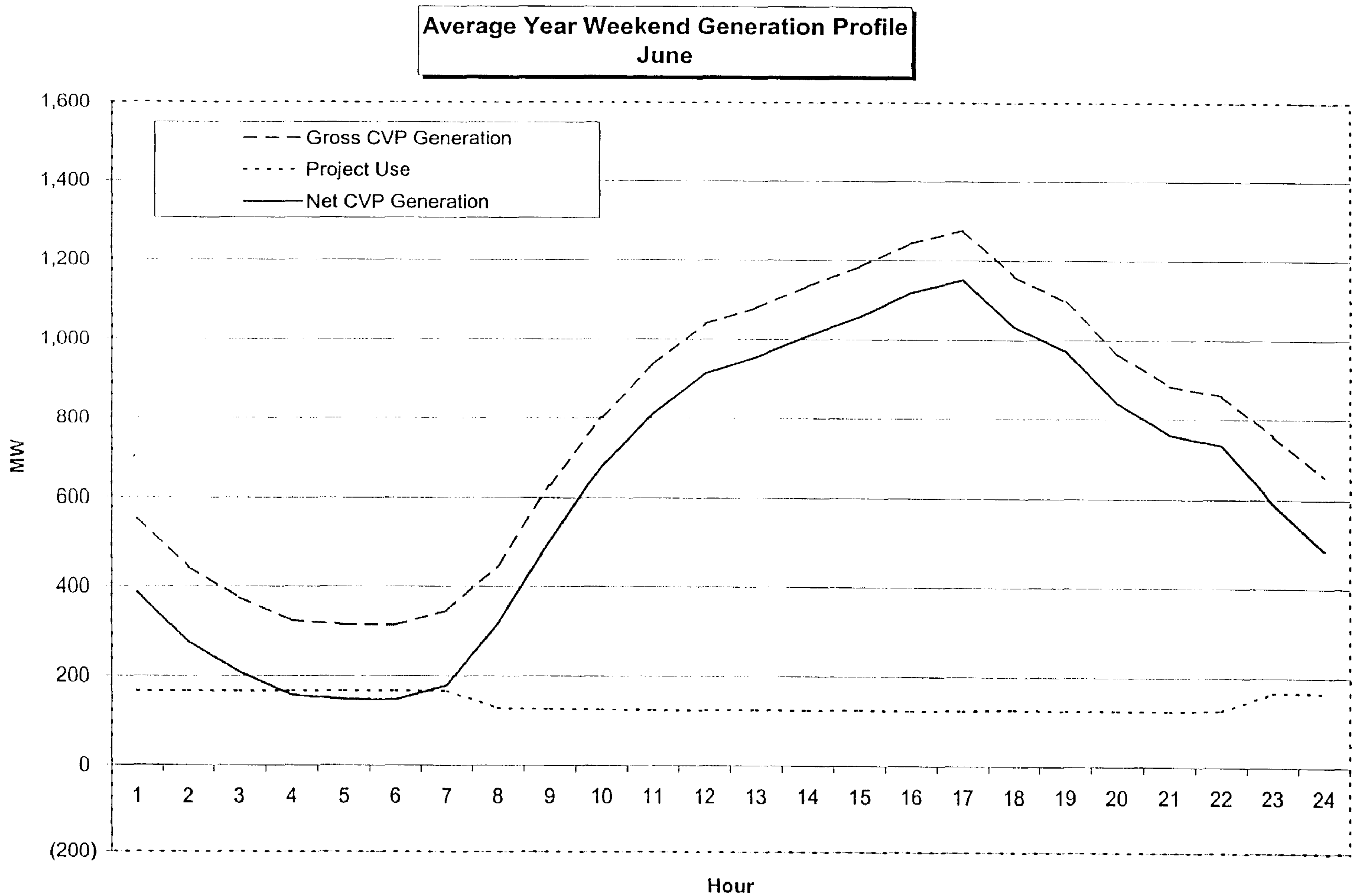
16
17
18
19
20
21
22
23
24
Hour

Fig. 6-6


Average Year Weekend Generation Profile
June
Gross CVP Generation
Project Use
Net CVP Generation
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1
2
3
4
5
6
7
8
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16
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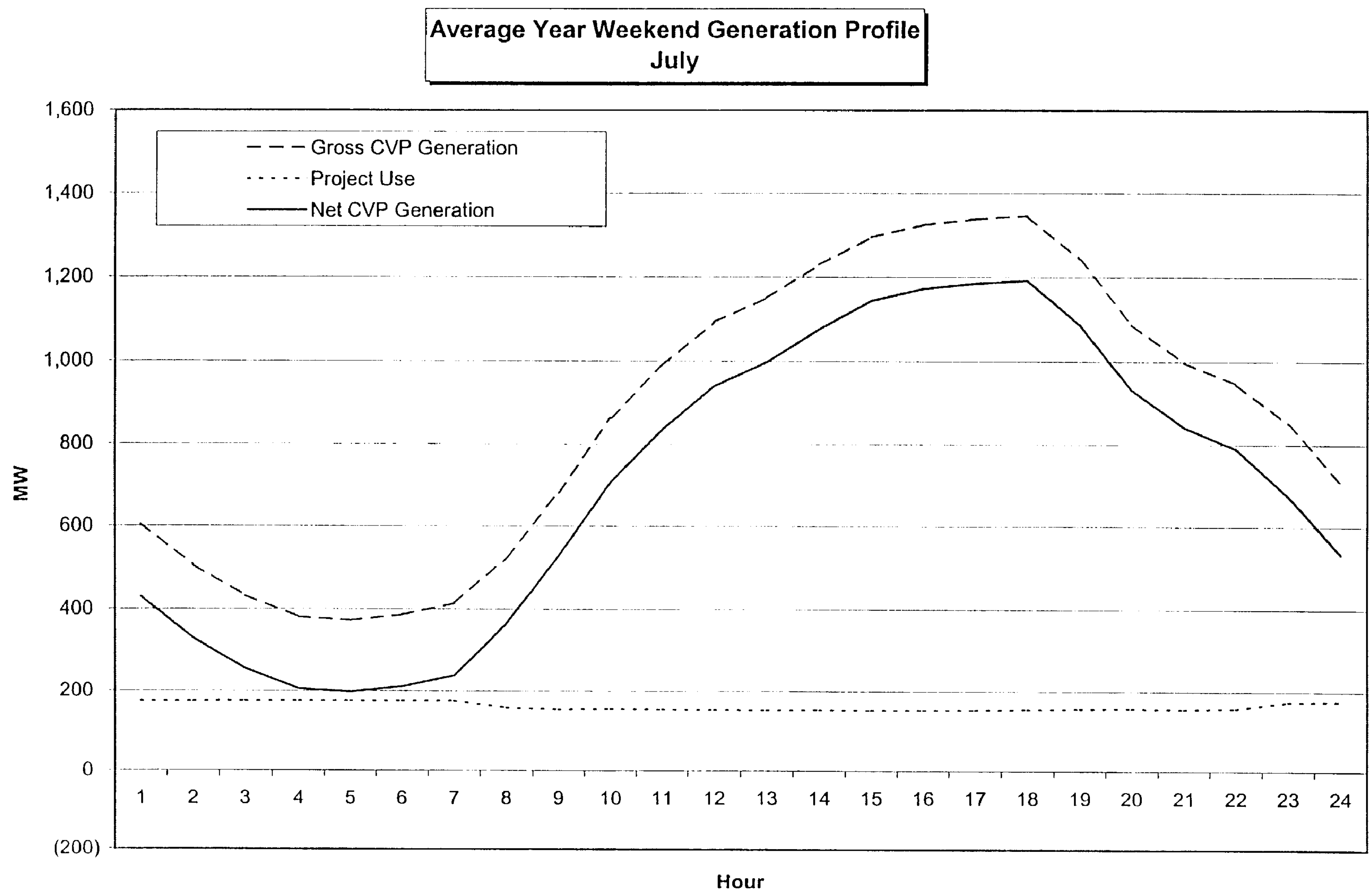
18
19
20
21
22
23
24
Hour

Fig. 6-7


Average Year Weekend Generation Profile
July
Gross CVP Generation
Project Use
Net CVP Generation
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1
2
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5
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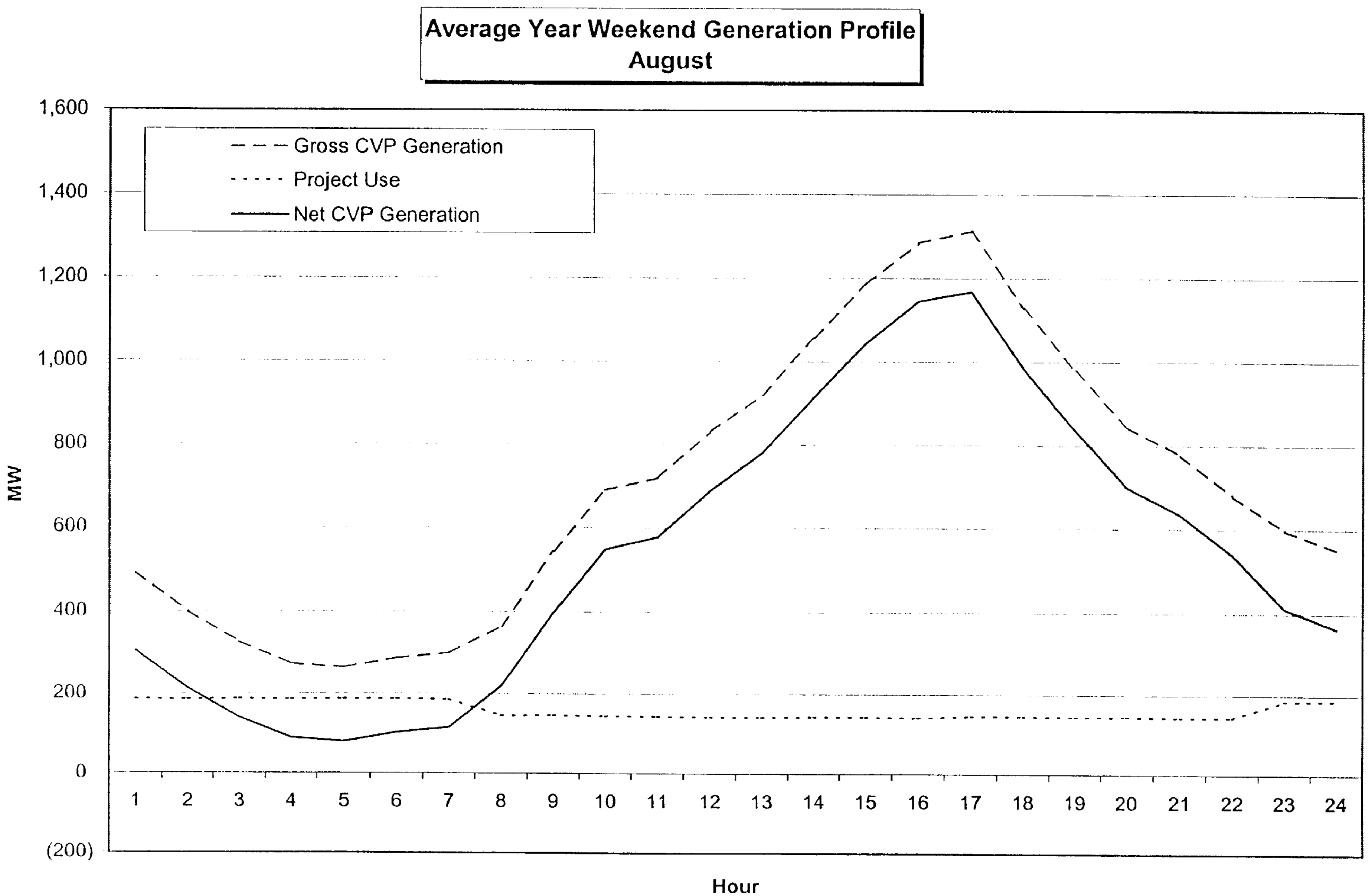
20
21
22
23
24
Hour

Fig. 6-8



Average Year Weekend Generation Profile
August
Gross CVP Generation
Project Use
Net CVP Generation
MW
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
1
2
3
4
5
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7
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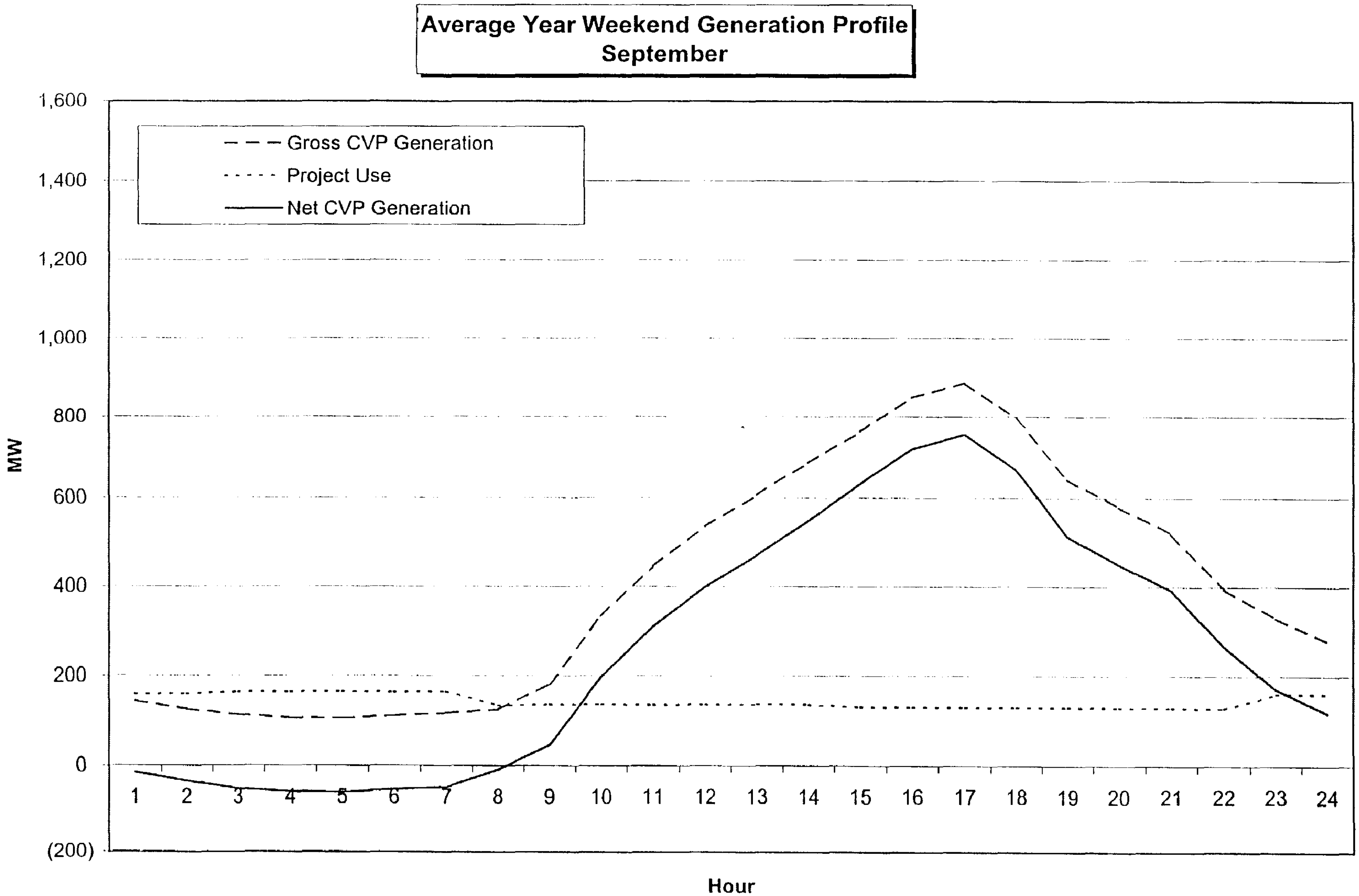
16
17
18
19
20
21
22
23
24
Hour

Fig. 6-9



Average Year Weekend Generation Profile
September
Gross CVP Generation
Project Use
Net CVP Generation
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1
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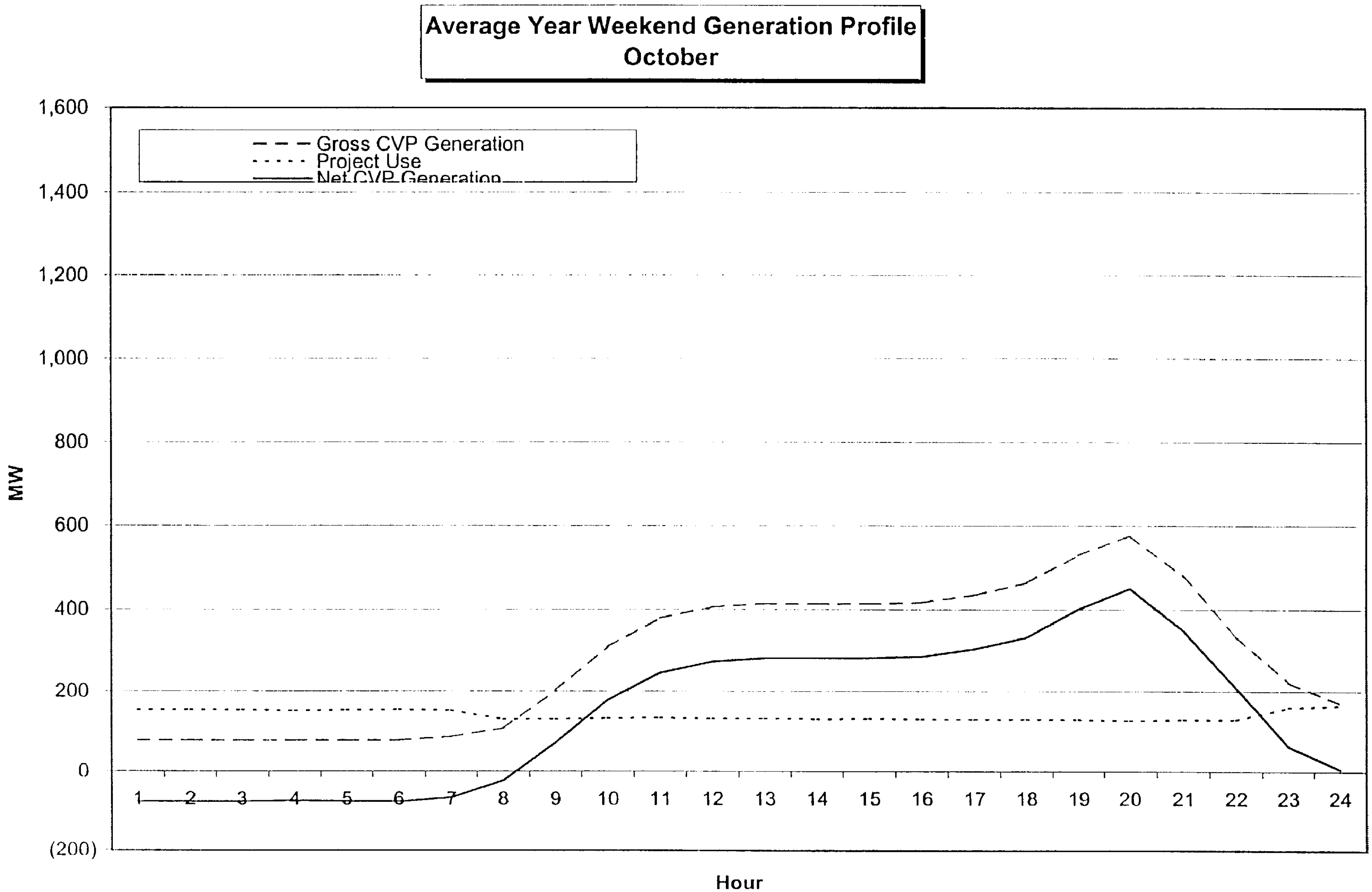
20
21
22
23
24
Hour

Fig. 6-10



Average Year Weekend Generation Profile
October
Gross CVP Generation
Project Use
Net CVP Generation
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1
2
3
4
5
6
7
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14
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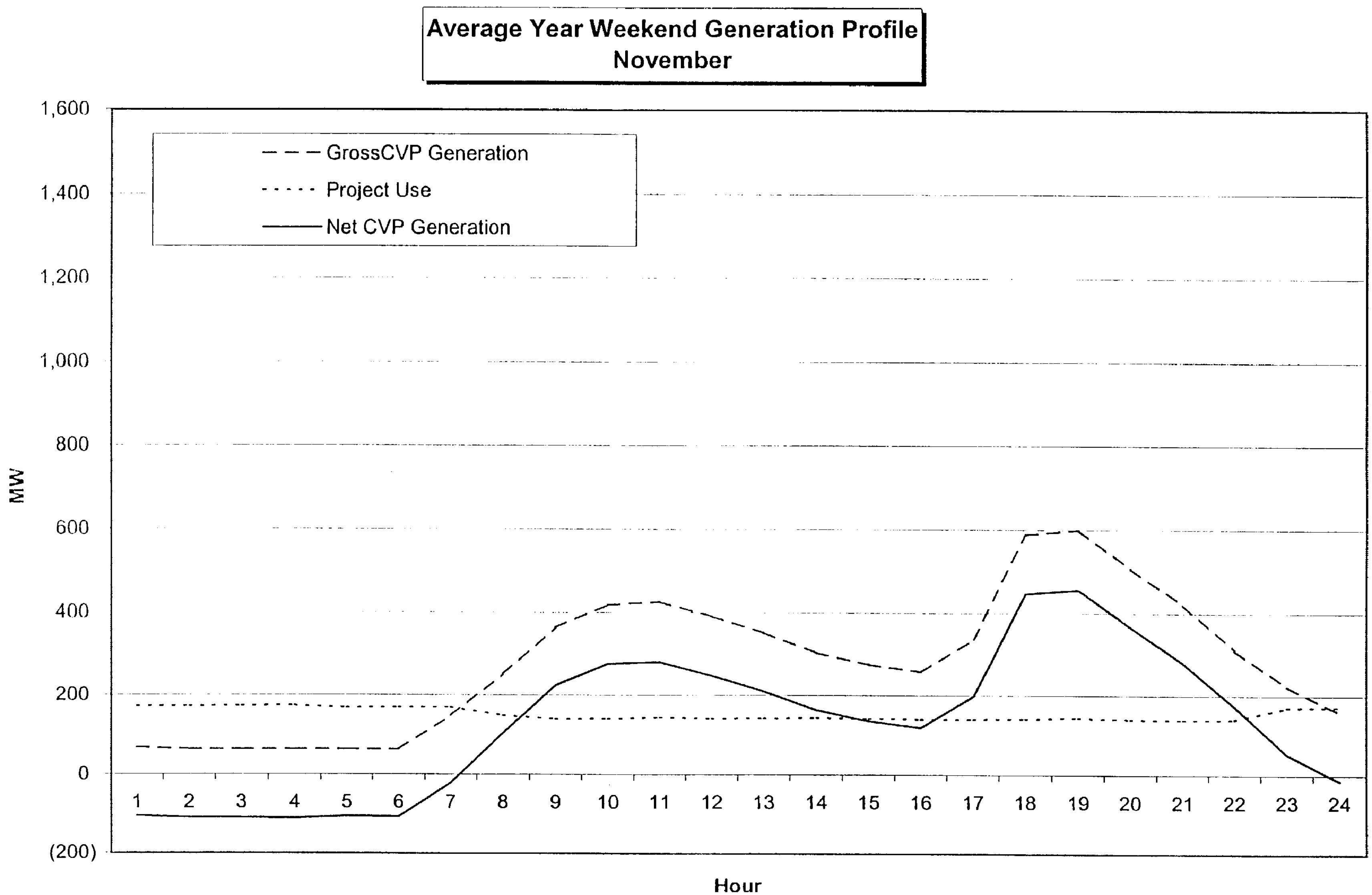
16
17
18
19
20
21
22
23
24
Hour

Fig. 6-11



Average Year Weekend Generation Profile
November
GrossCVP Generation
Project Use
Net CVP Generation
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1
2
3
4
5
6
7
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16
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18
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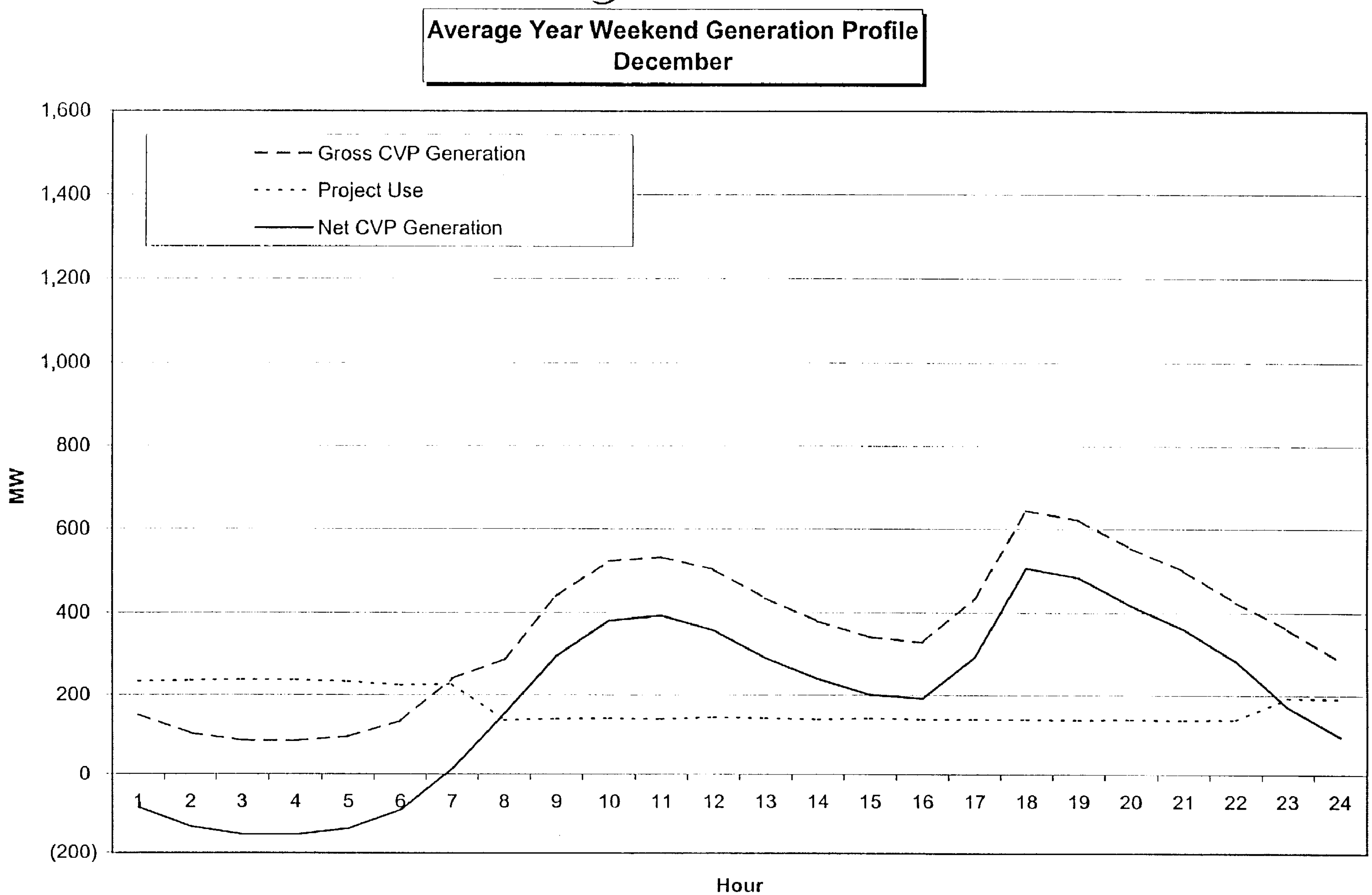
20
21
22
23
24
Hour

Fig. 6-12



Average Year Weekend Generation Profile
December
Gross CVP Generation
Project Use
Net CVP Generation
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1
2
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14
15
16
17
18
19
20
21
22
23
24
Hour

Daily Generation Profile

Dry Year Generation

Peak Weekday

Figures 7-1 thru 7-12

Fig. 7-1

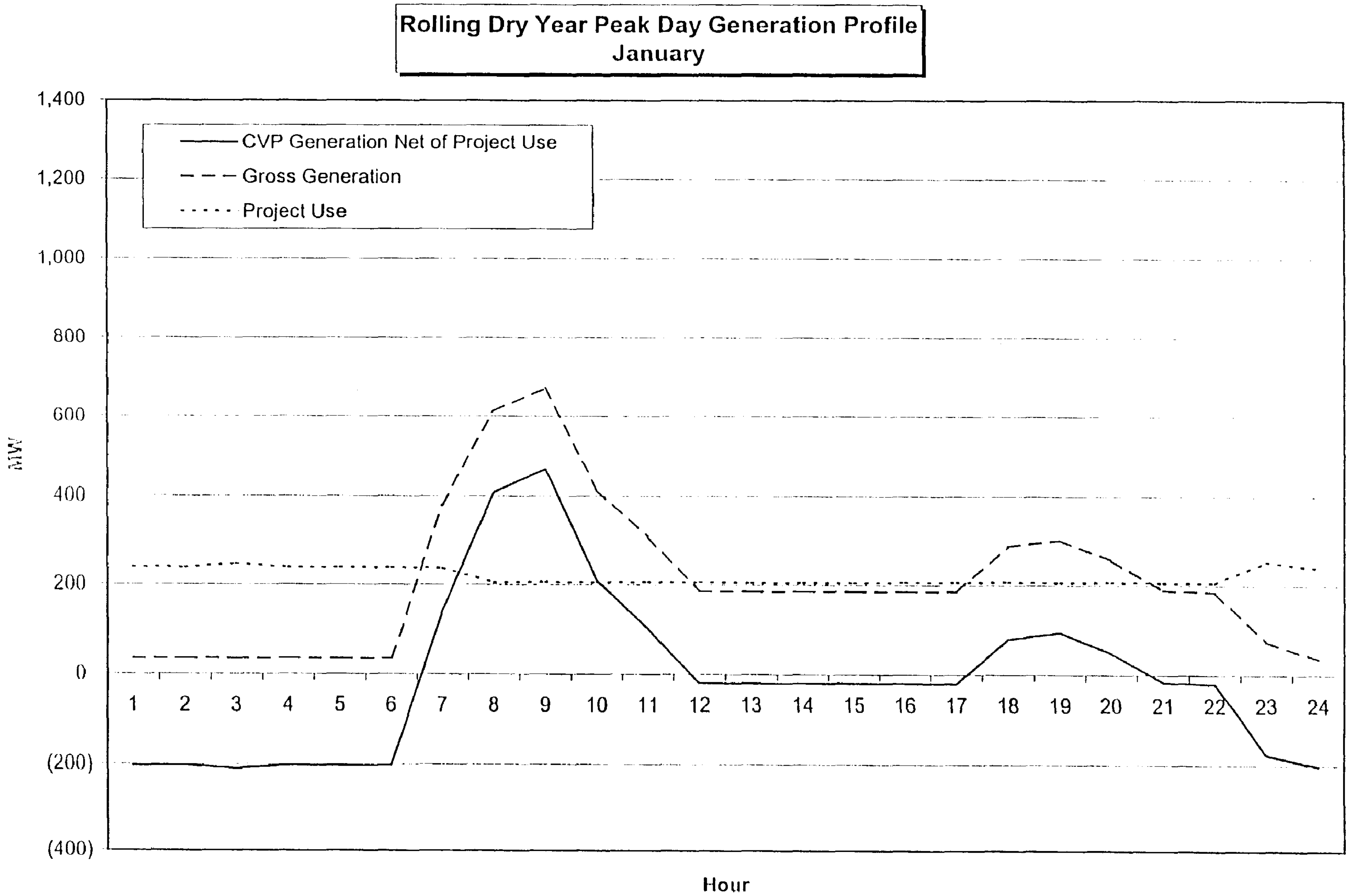
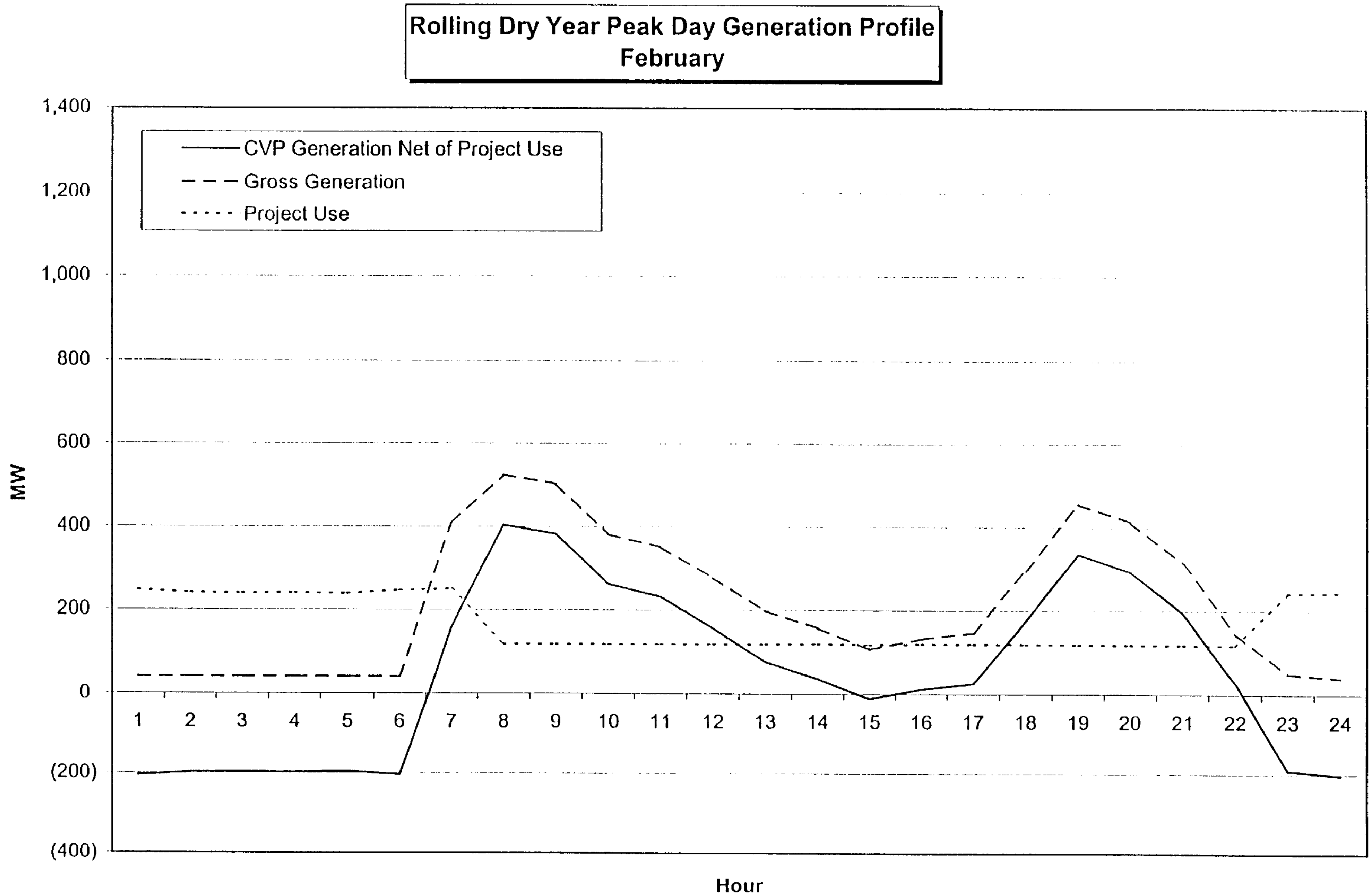
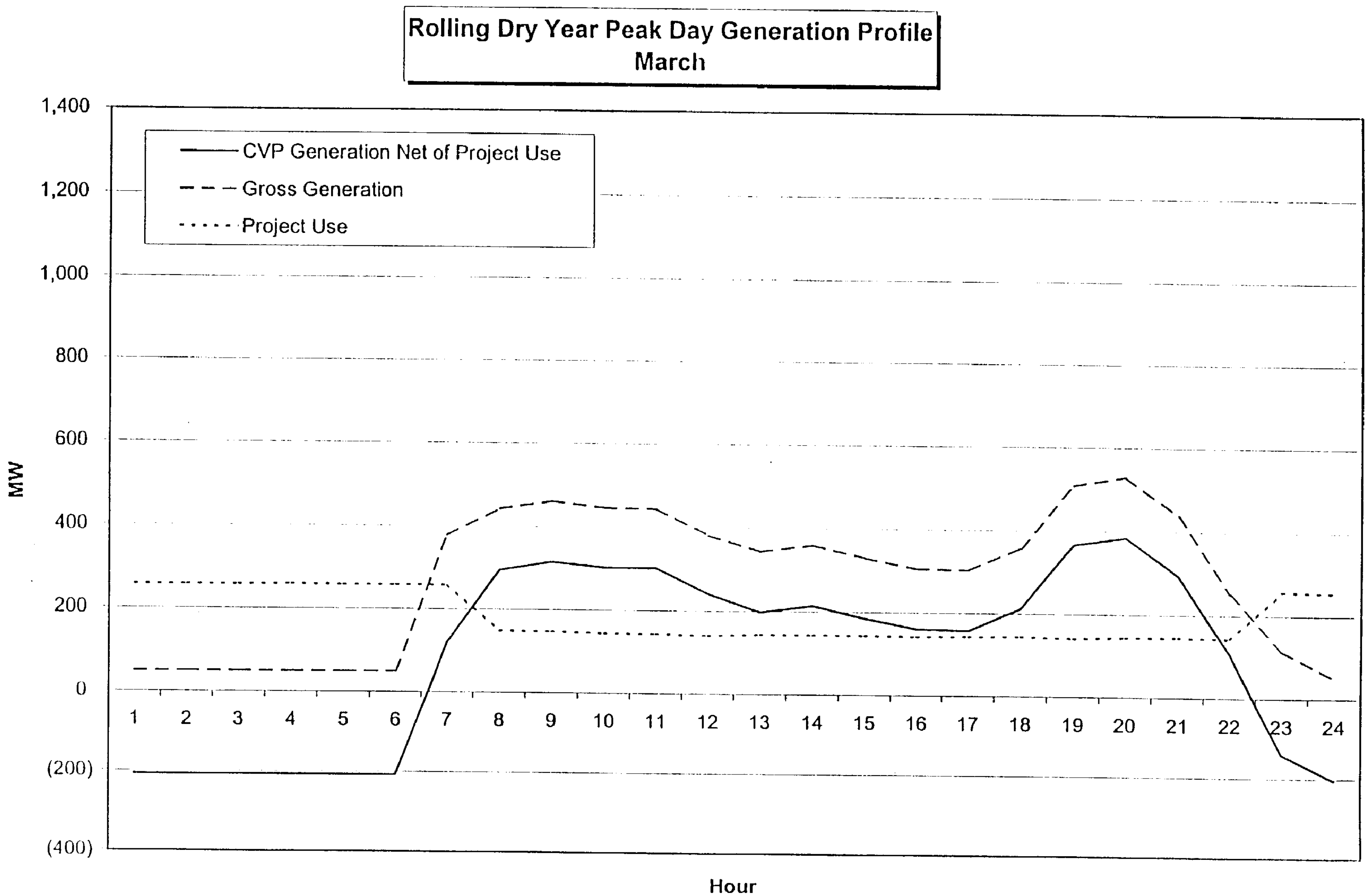

Rolling Dry Year Peak Day Generation Profile
January
CVP Generation Net of Project Use
Gross Generation
Project Use
1,400
1,200
1,000
800
600
400
200
0
(200)
(400)
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

Fig. 7-2



Rolling Dry Year Peak Day Generation Profile
February
CVP Generation Net of Project Use
Gross Generation
Project Use
1,400
1,200
1,000
800
600
400
200
0
(200)
(400)
MW
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Hour

Fig 7-3


Rolling Dry Year Peak Day Generation Profile
March
CVP Generation Net of Project Use
Gross Generation
Project Use
1,400
1,200
1,000
800
600
400
200
0
(200)
(400)
MW
1
2
3
4
5
6
7
8
9
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14
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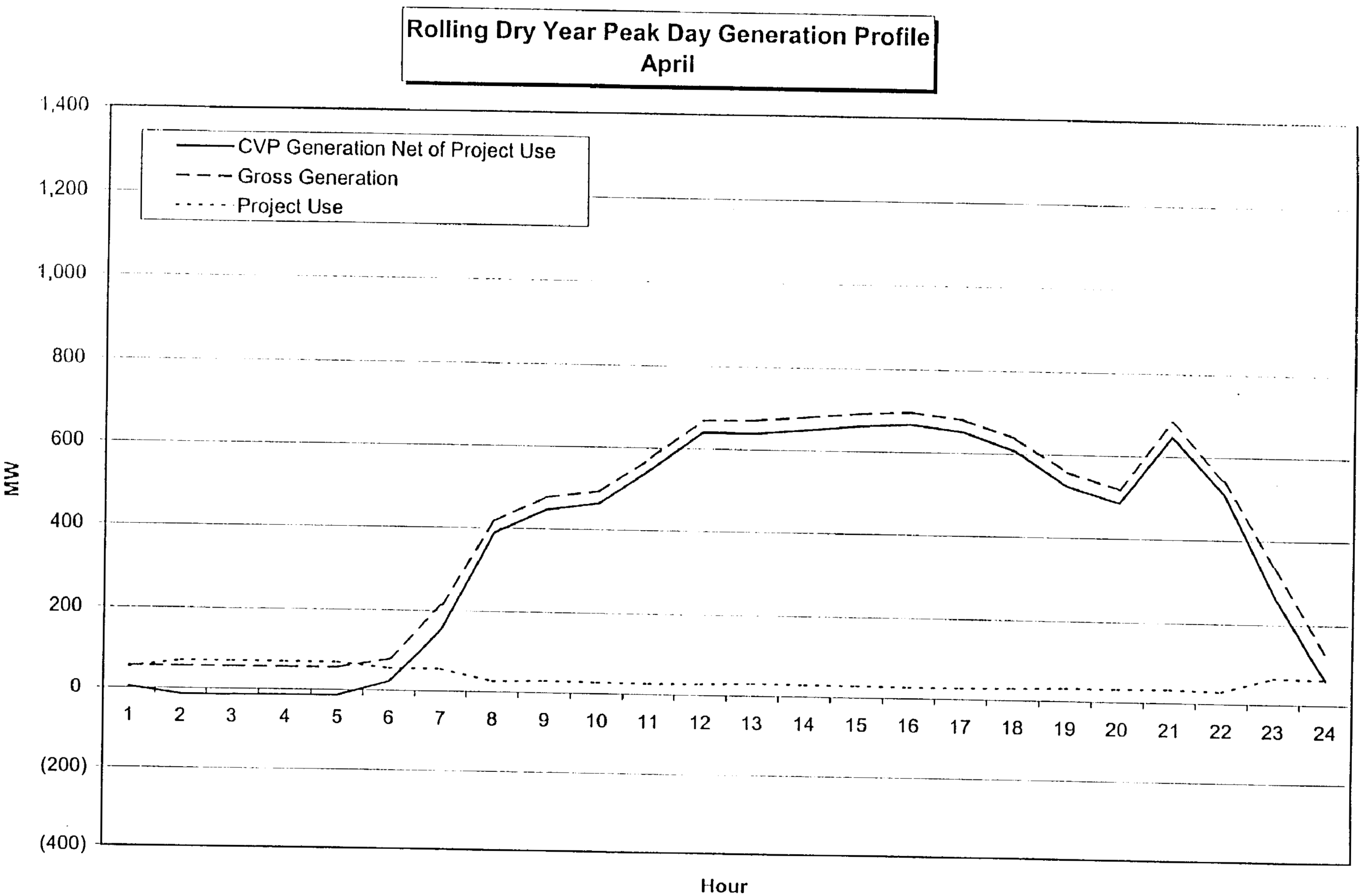
16
17
18
19
20
21
22
23
24
Hour

Fig. 7-4


Rolling Dry Year Peak Day Generation Profile
April
CVP Generation Net of Project Use
Gross Generation
Project Use
1,400
1,200
1,000
800
600
400
200
0
(200)
(400)
MW
1
2
3
4
5
6
7
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16
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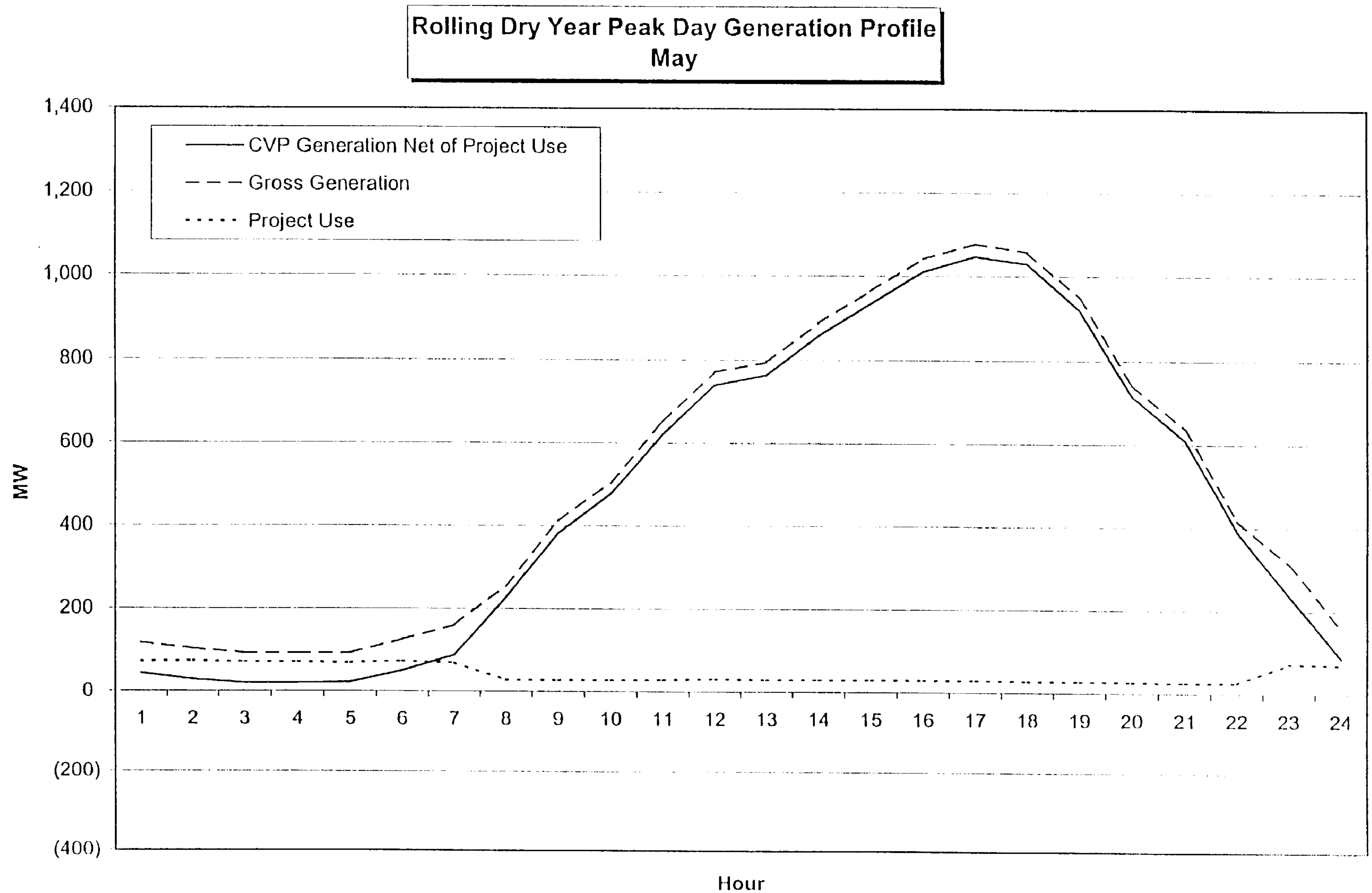
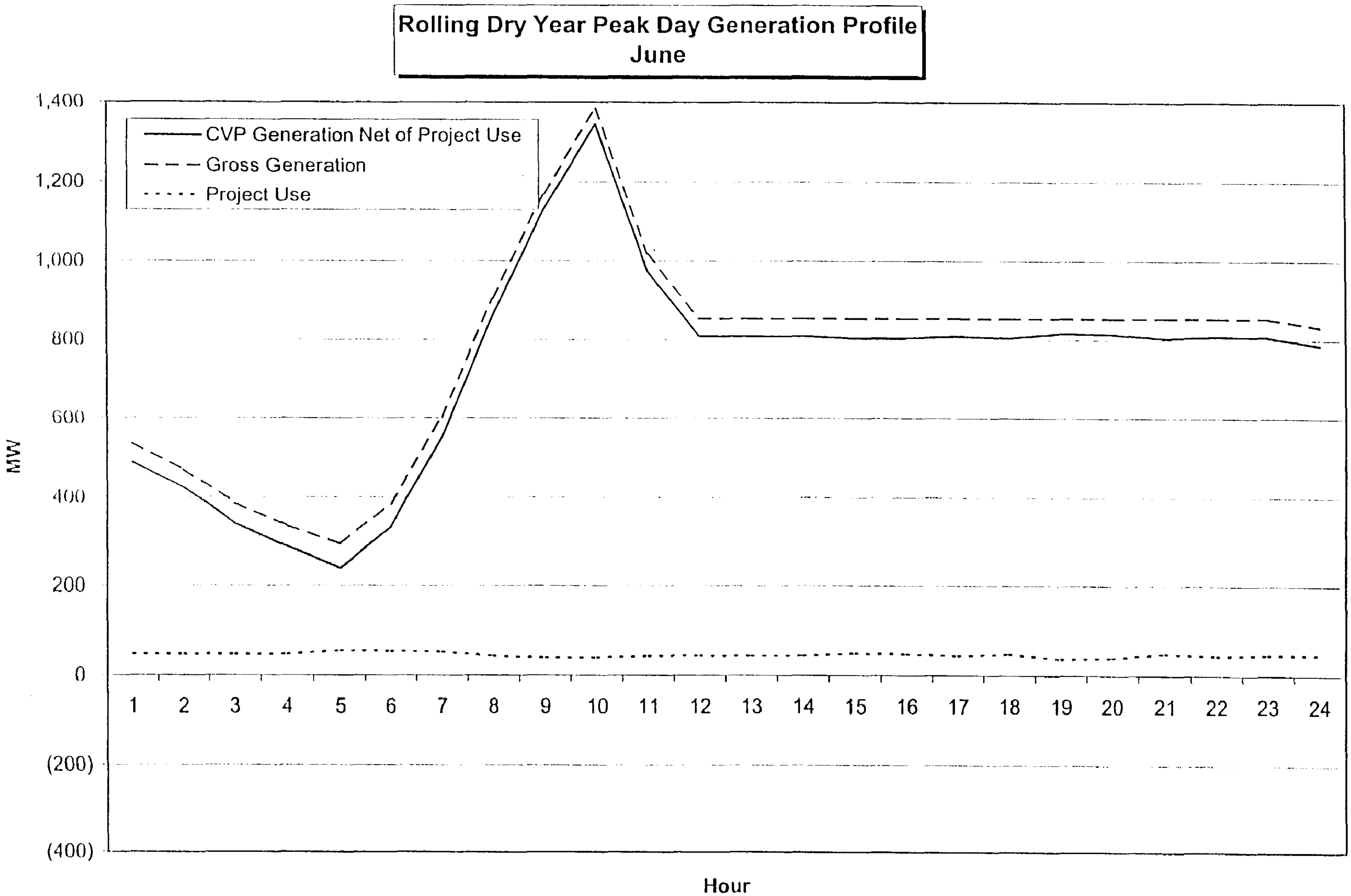
19
20
21
22
23
24
Hour

Fig 7-5



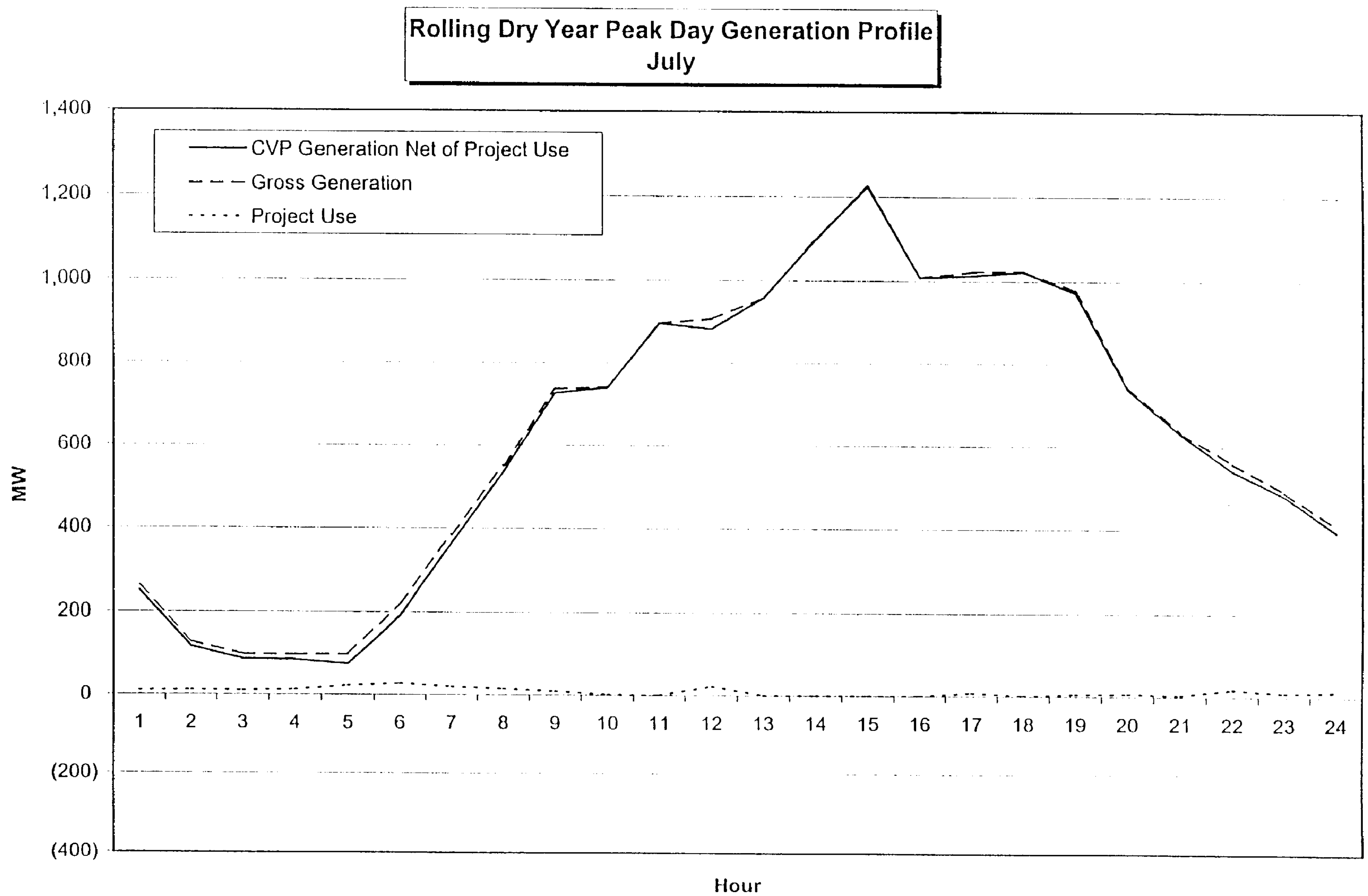
Rolling Dry Year Peak Day Generation Profile
May
CVP Generation Net of Project Use
Gross Generation
Project Use
1,400
1,200
1,000
800
600
400
200
0
(200)
(400)
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

Fig 7-6



Rolling Dry Year Peak Day Generation Profile
June
CVP Generation Net of Project Use
Gross Generation
Project Use
1,400
1,200
1,000
800
600
400
200
0
(200)
(400)
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

Fig. 7-7


Rolling Dry Year Peak Day Generation Profile
July
CVP Generation Net of Project Use
Gross Generation
Project Use
MW
1,400
1,200
1,000
800
600
400
200
0
(200)
(400)
1
2
3
4
5
6
7
8
9
10
11
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14
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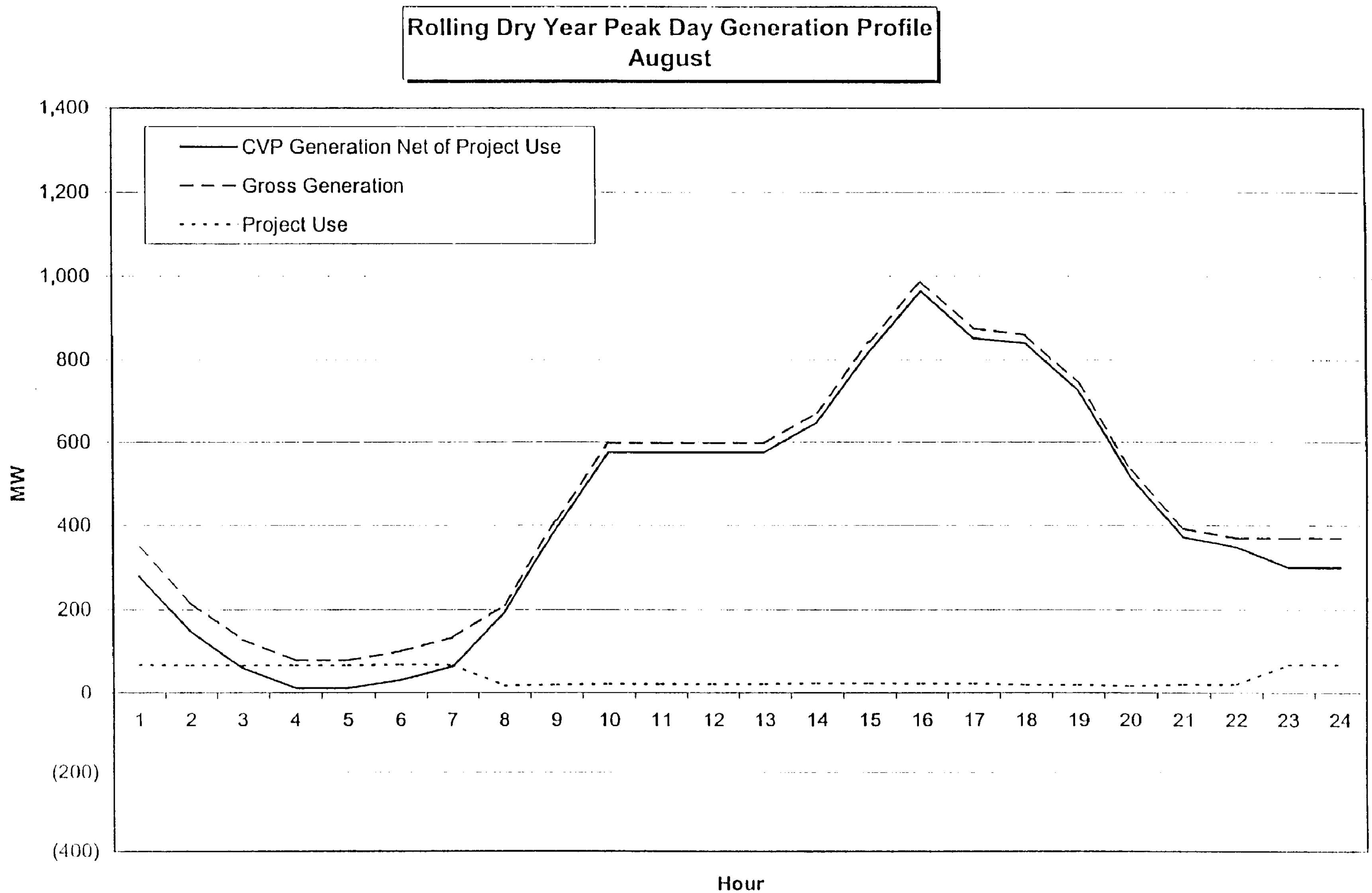
16
17
18
19
20
21
22
23
24
Hour

Fig 7-8



Rolling Dry Year Peak Day Generation Profile
August
CVP Generation Net of Project Use
Gross Generation
Project Use
1,400
1,200
1,000
800
600
400
200
0
(200)
(400)
MW
1
2
3
4
5
6
7
8
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14
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16
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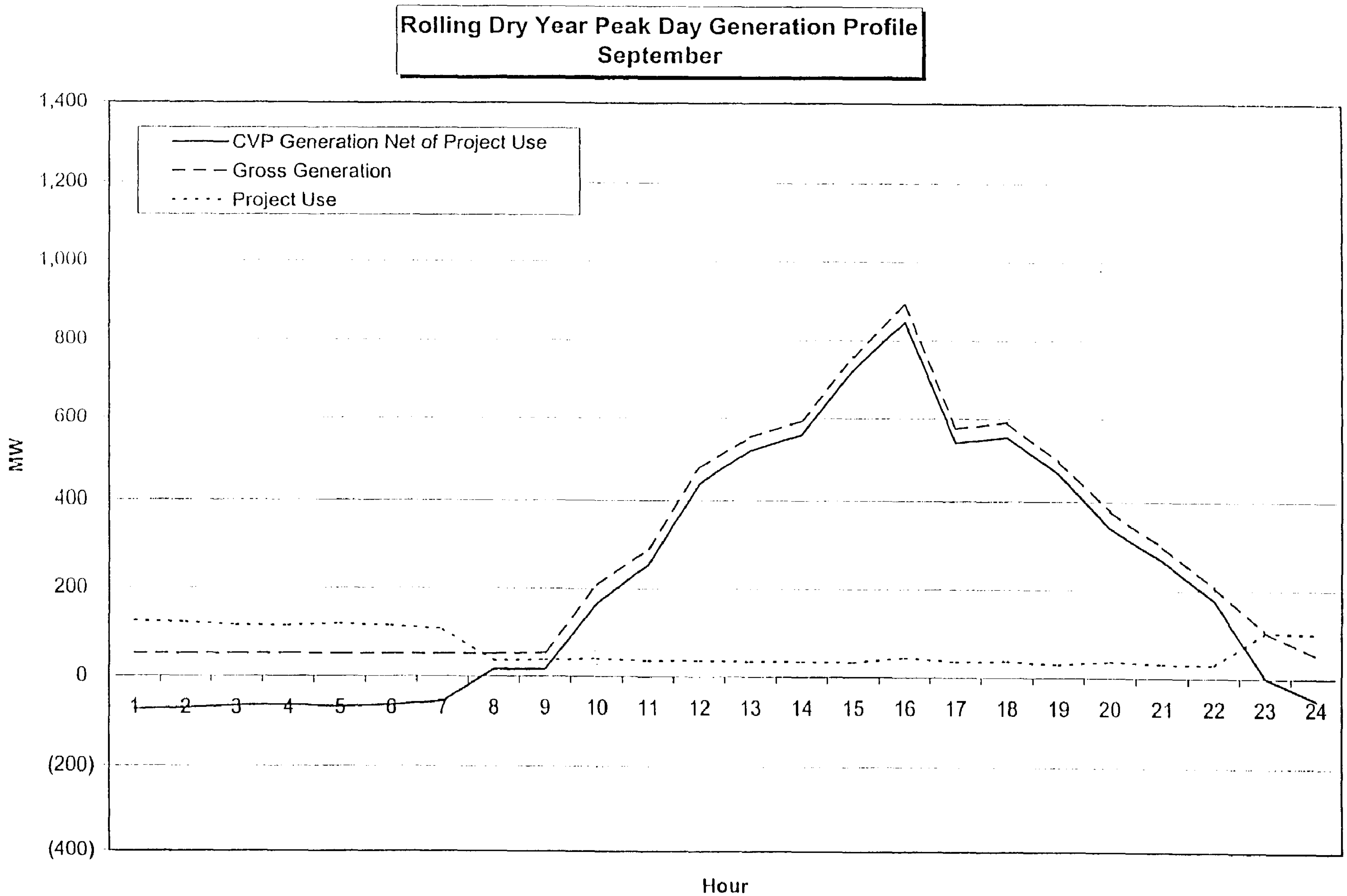
20
21
22
23
24
Hour

Fig. 7-9



Rolling Dry Year Peak Day Generation Profile
September
CVP Generation Net of Project Use
Gross Generation
Project Use
1,400
1,200
1,000
800
600
400
200
0
(200)
(400)
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

Fig. 7-10

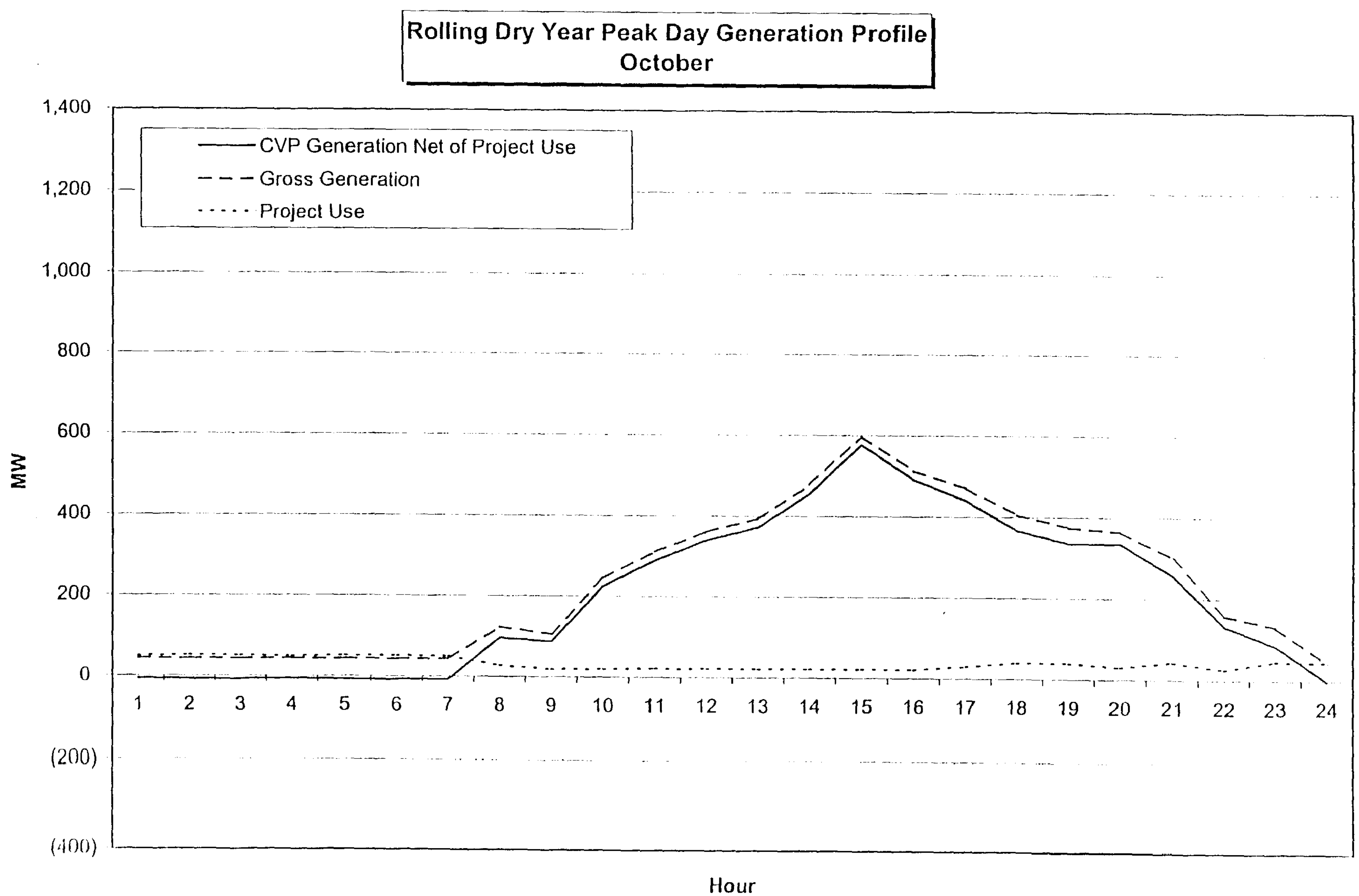
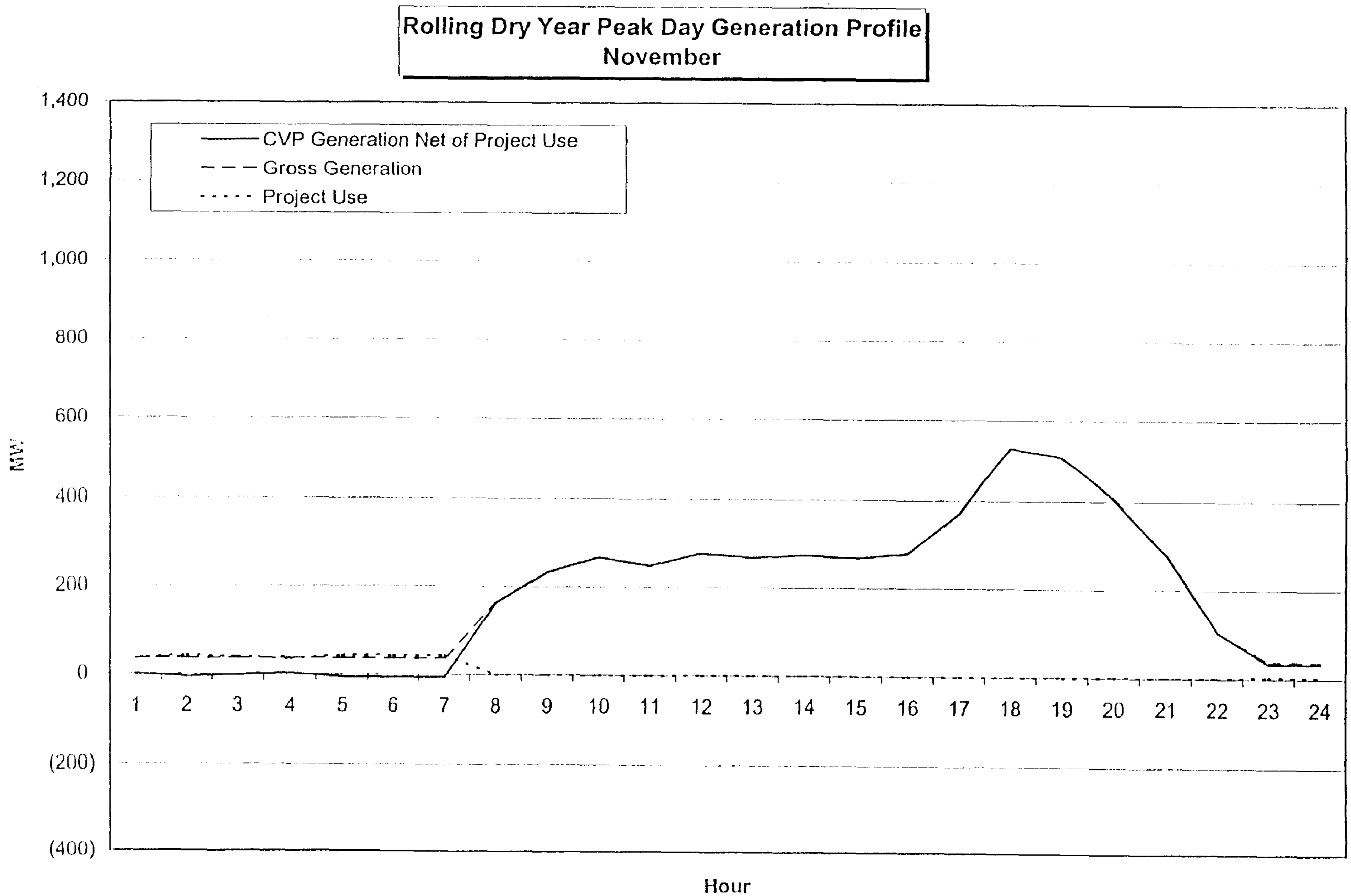
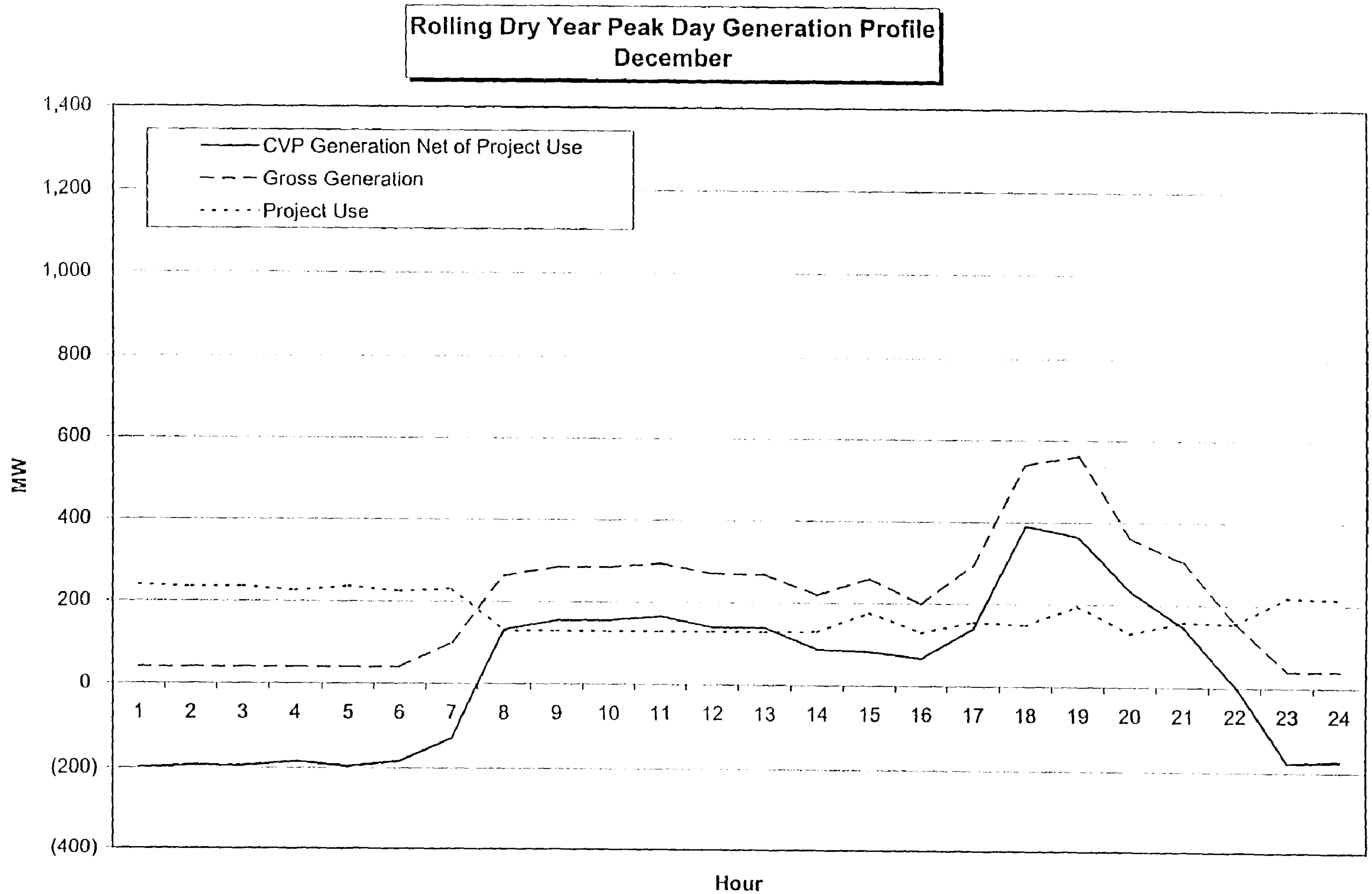

Rolling Dry Year Peak Day Generation Profile
October
CVP Generation Net of Project Use
Gross Generation
Project Use
MW
1,400
1,200
1,000
800
600
400
200
0
(200)
(400)
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Hour

Fig 7-11



Rolling Dry Year Peak Day Generation Profile
November
CVP Generation Net of Project Use
Gross Generation
Project Use
1,400
1,200
1,000
800
600
400
200
0
(200)
(400)
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

Fig. 7-12



Rolling Dry Year Peak Day Generation Profile
December
CVP Generation Net of Project Use
Gross Generation
Project Use
MW
1,400
1,200
1,000
800
600
400
200
0
(200)
(400)
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

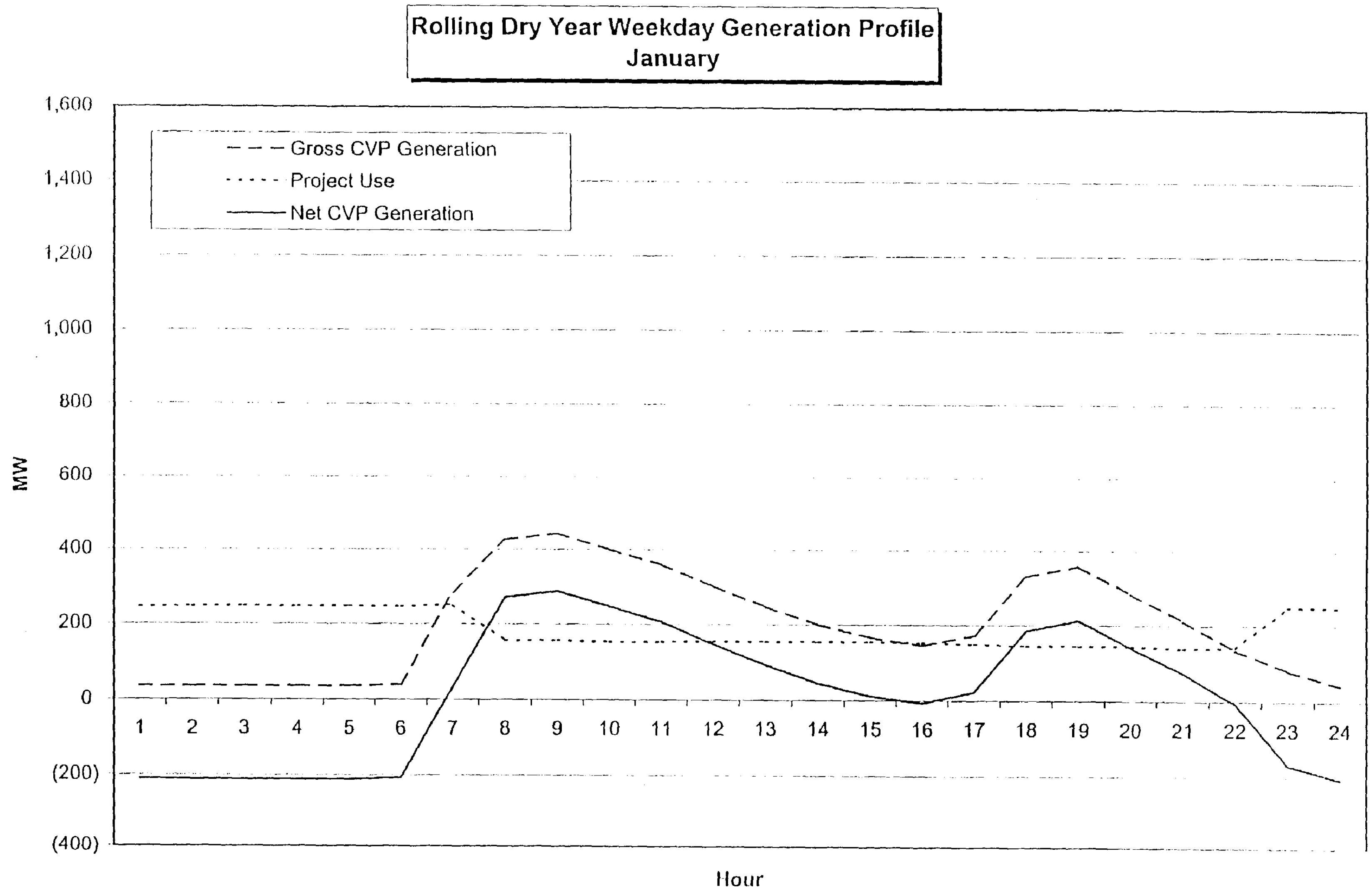
Daily Generation Profile

Dry Year Generation

Average Weekday

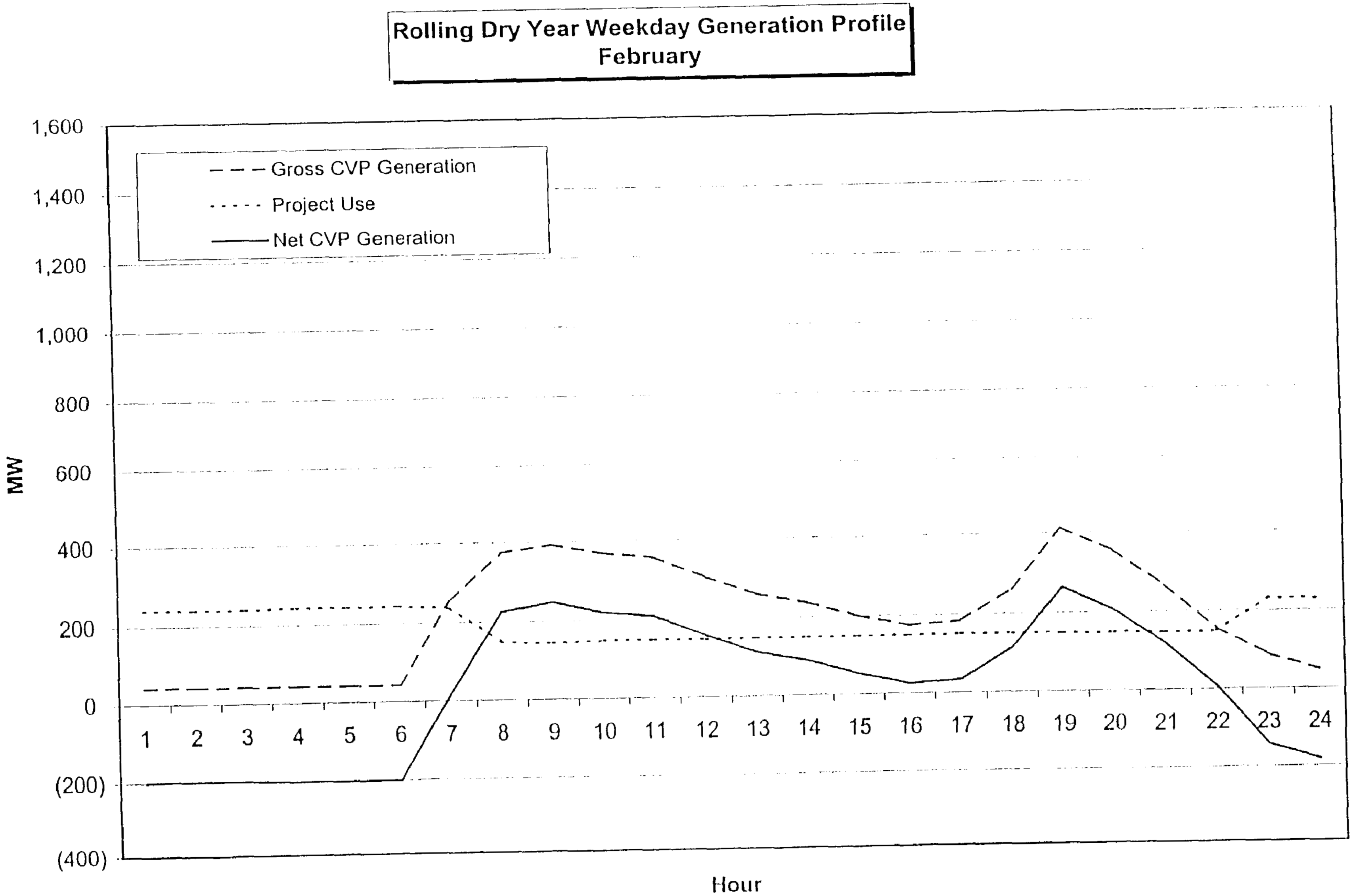
Figures 8-1 thru 8-12

Fig. 8-1



Rolling Dry Year Weekday Generation Profile
January
Gross CVP Generation
Project Use
Net CVP Generation
MW
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
(400)
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

Fig. 8-2



Rolling Dry Year Weekday Generation Profile
February
Gross CVP Generation
Project Use
Net CVP Generation
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
(400)
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

Fig. 8-3

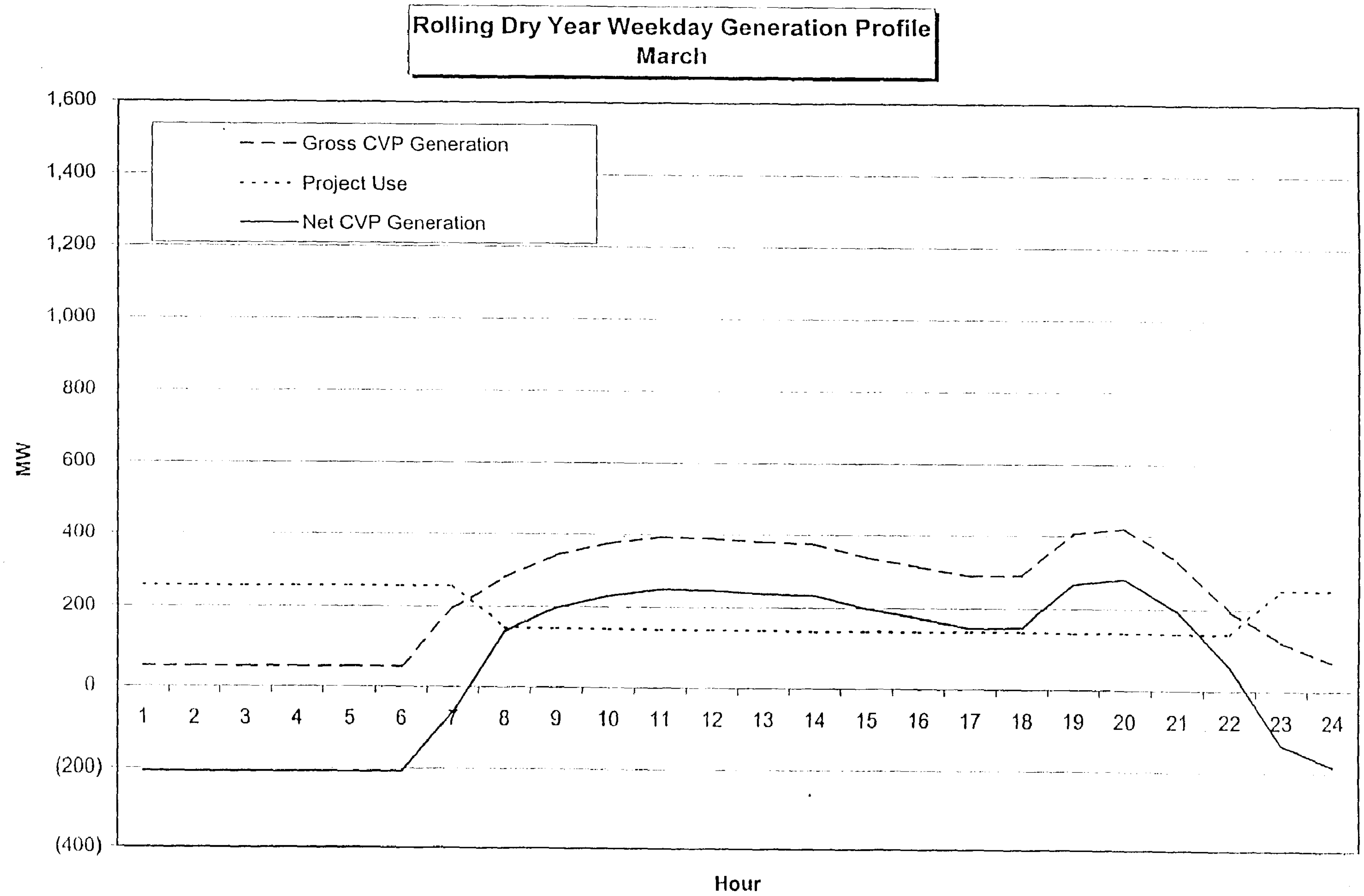

Rolling Dry Year Weekday Generation Profile
March
Gross CVP Generation
Project Use
Net CVP Generation
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
(400)
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

Fig 8-4

Rolling Dry Year Weekday Generation Profile
April

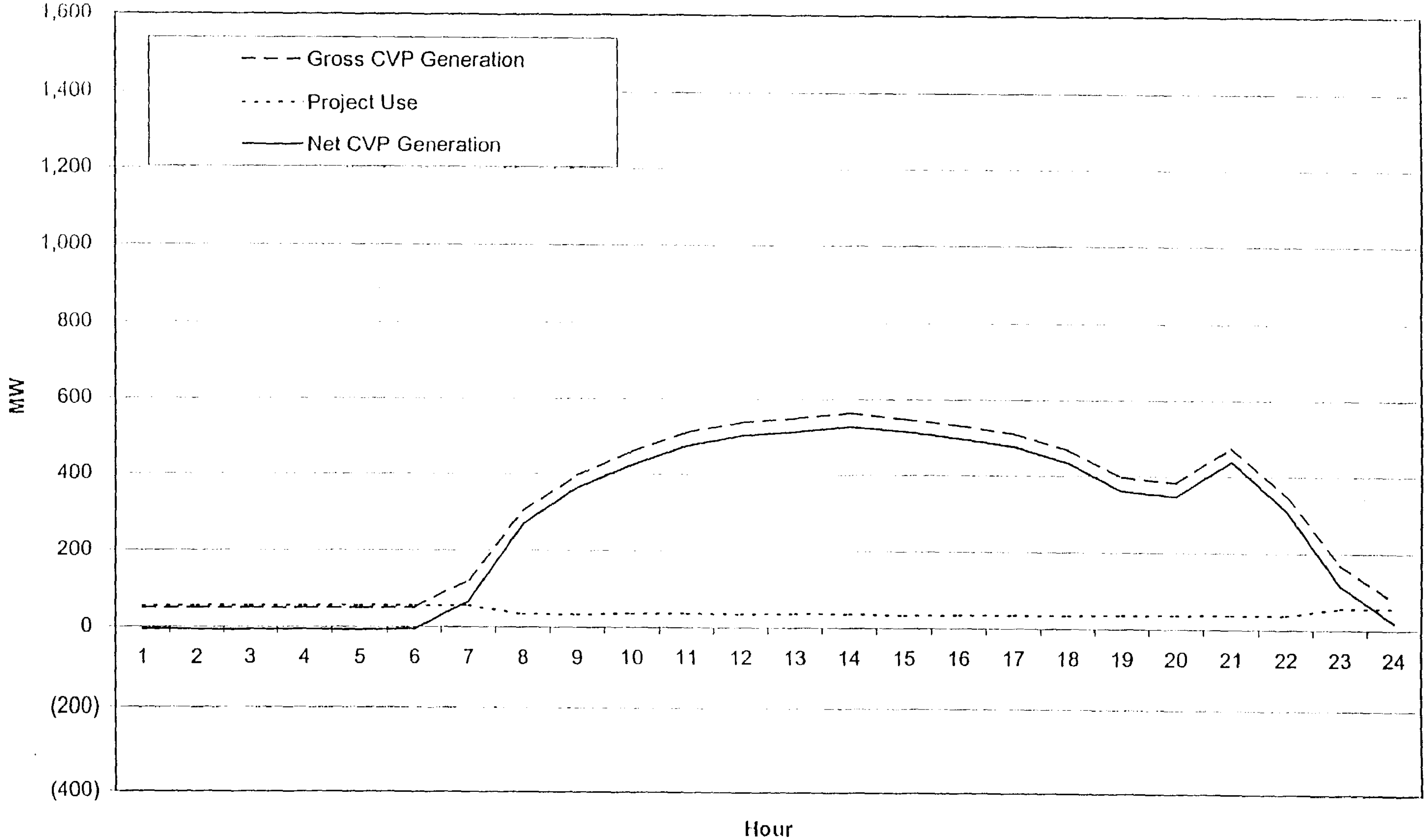


Fig. 8.5

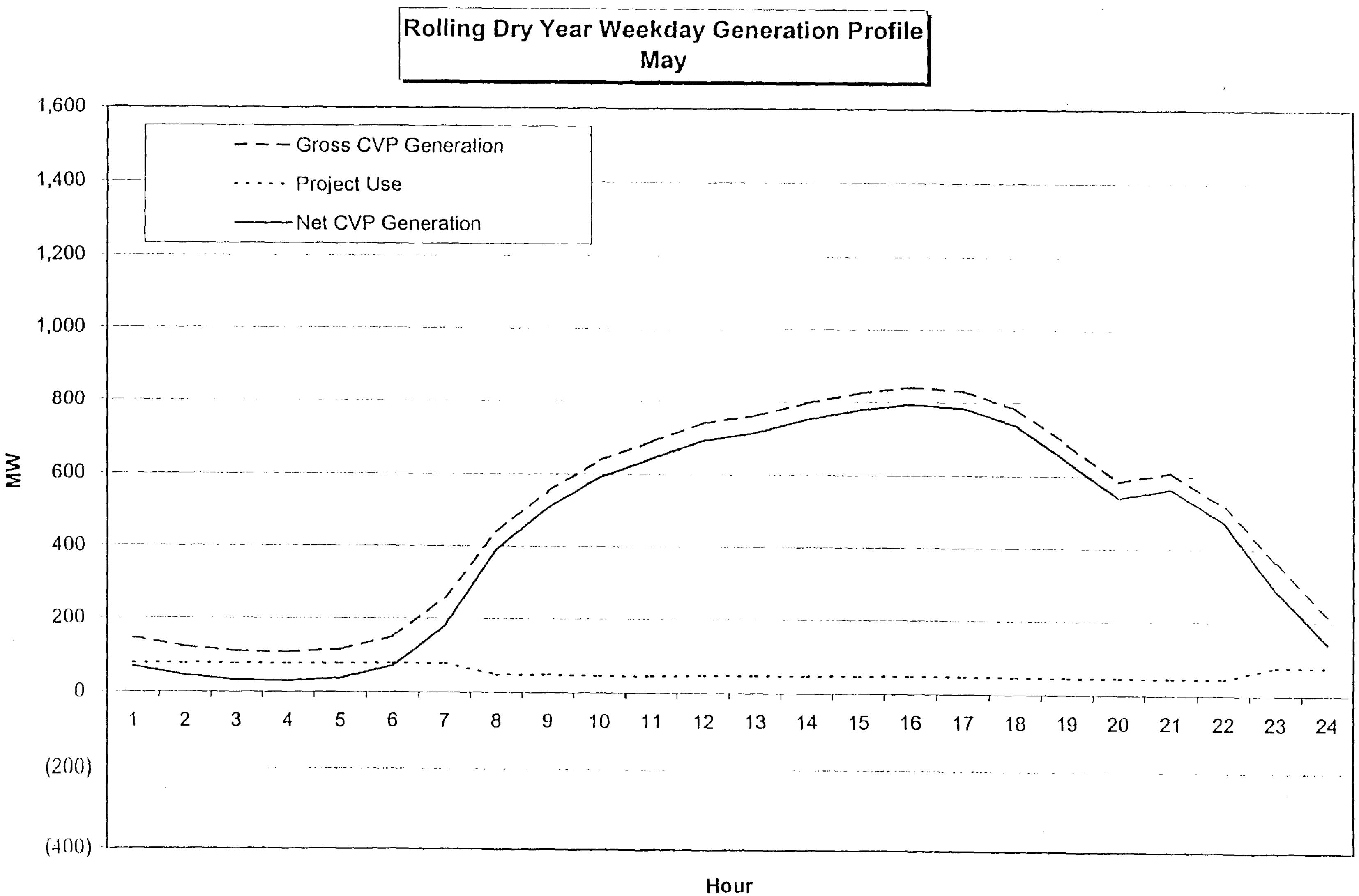

Rolling Dry Year Weekday Generation Profile
May
Gross CVP Generation
Project Use
Net CVP Generation
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
(400)
MW
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Hour

Fig. 8-6

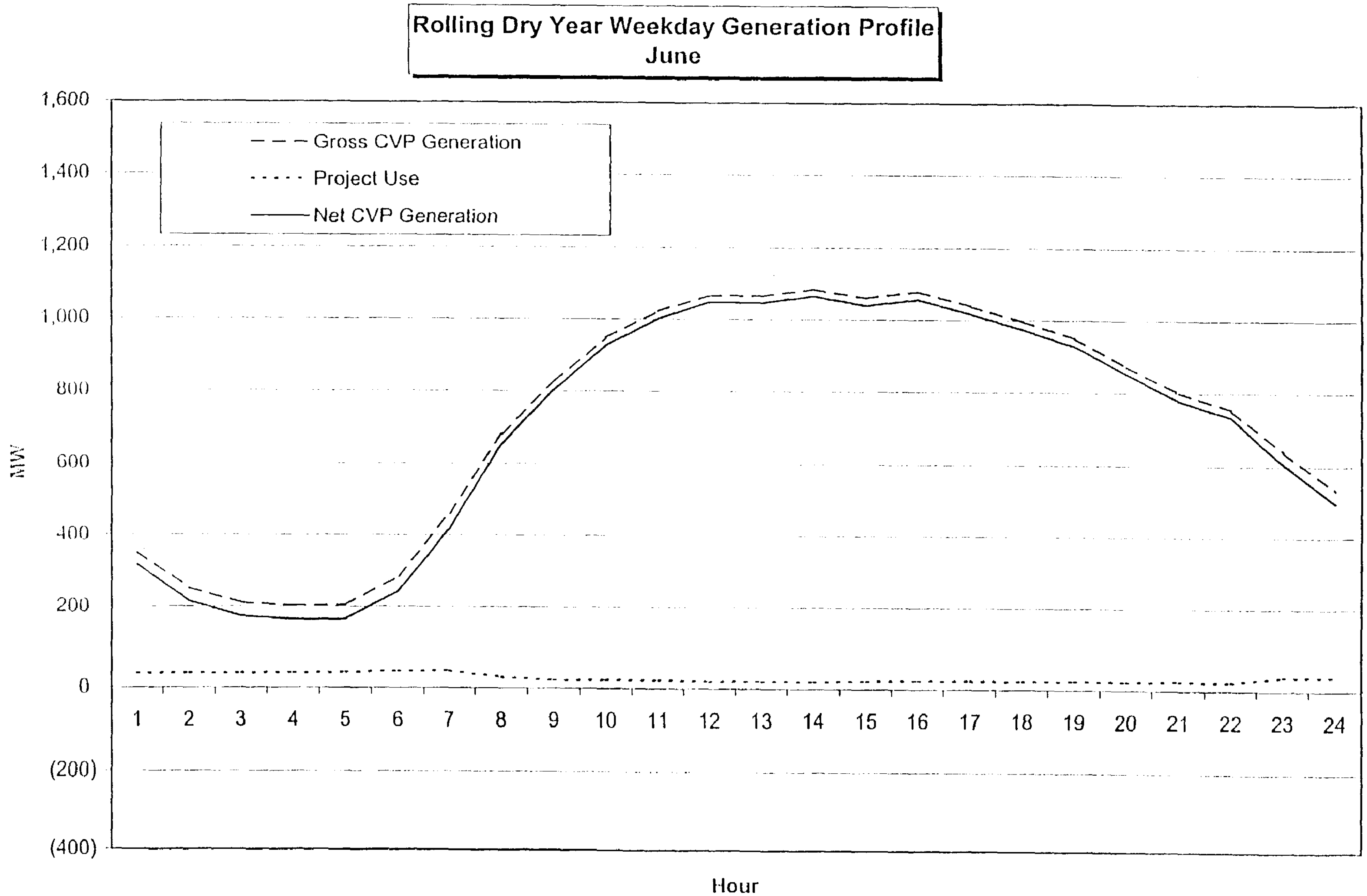

Rolling Dry Year Weekday Generation Profile
June
Gross CVP Generation
Project Use
Net CVP Generation
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
(400)
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

Fig. 8-7

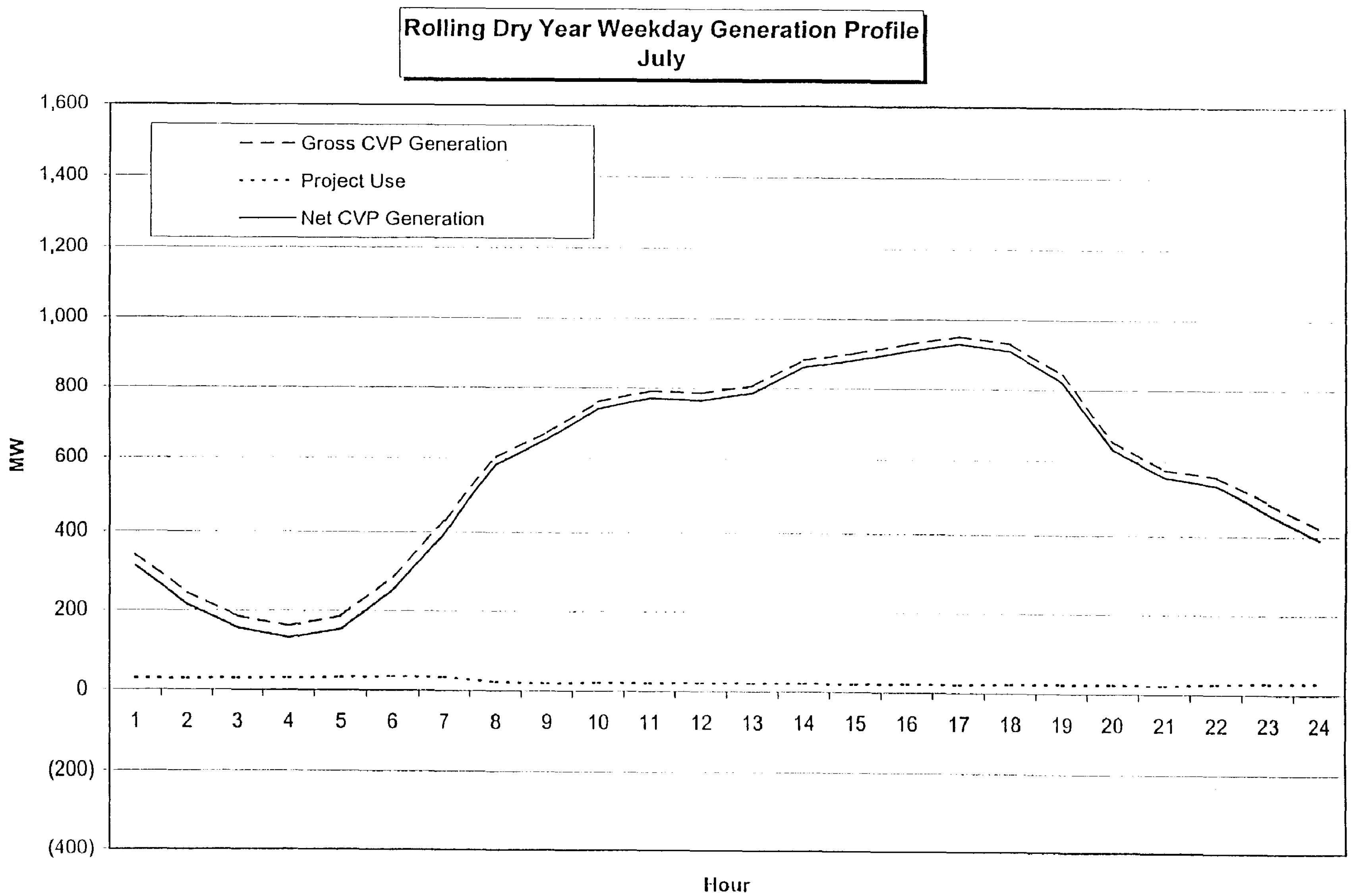

Rolling Dry Year Weekday Generation Profile
July
Gross CVP Generation
Project Use
Net CVP Generation
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
(400)
MW
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Hour

Fig. 8-8

Rolling Dry Year Weekday Generation Profile
August

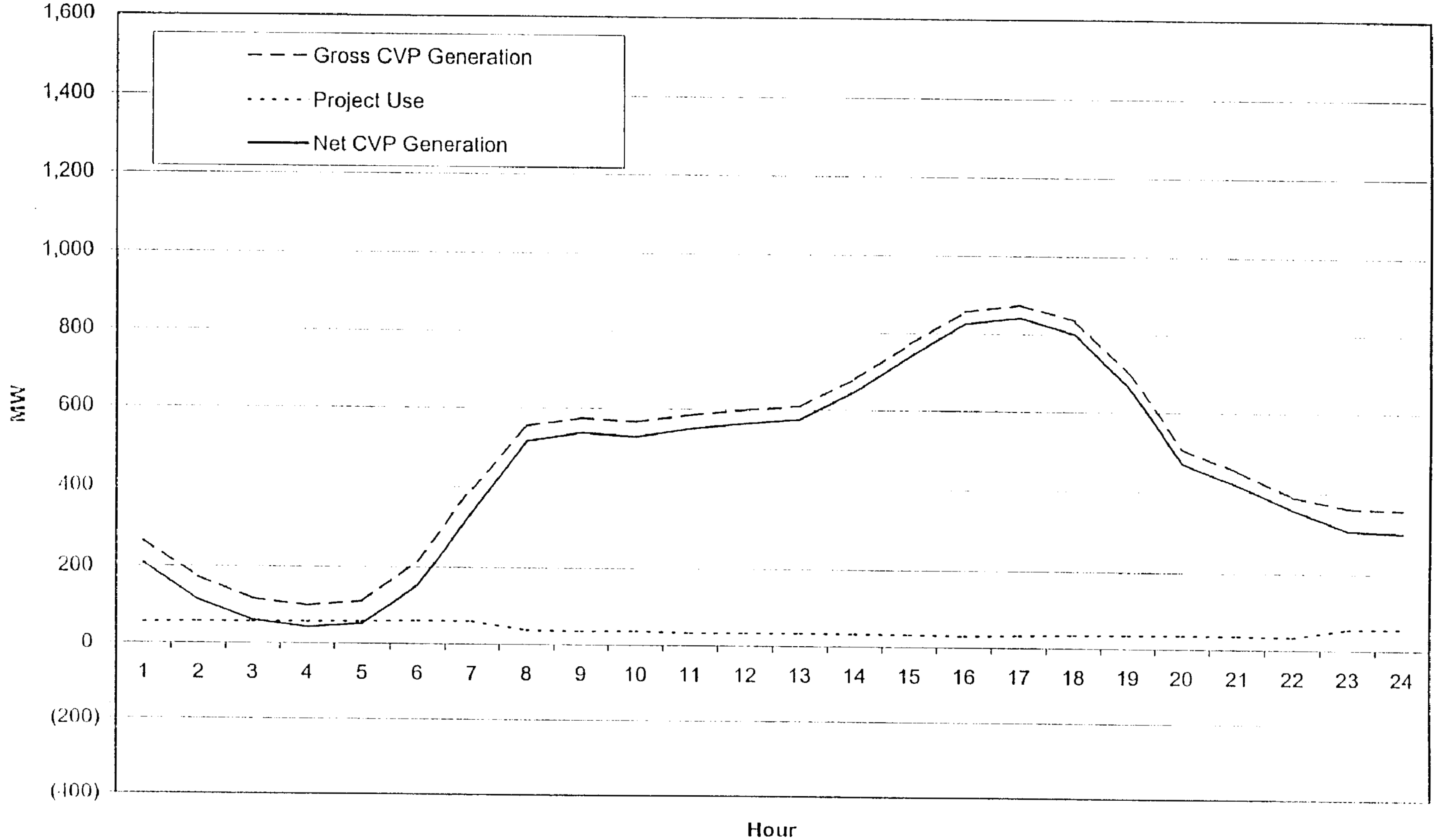
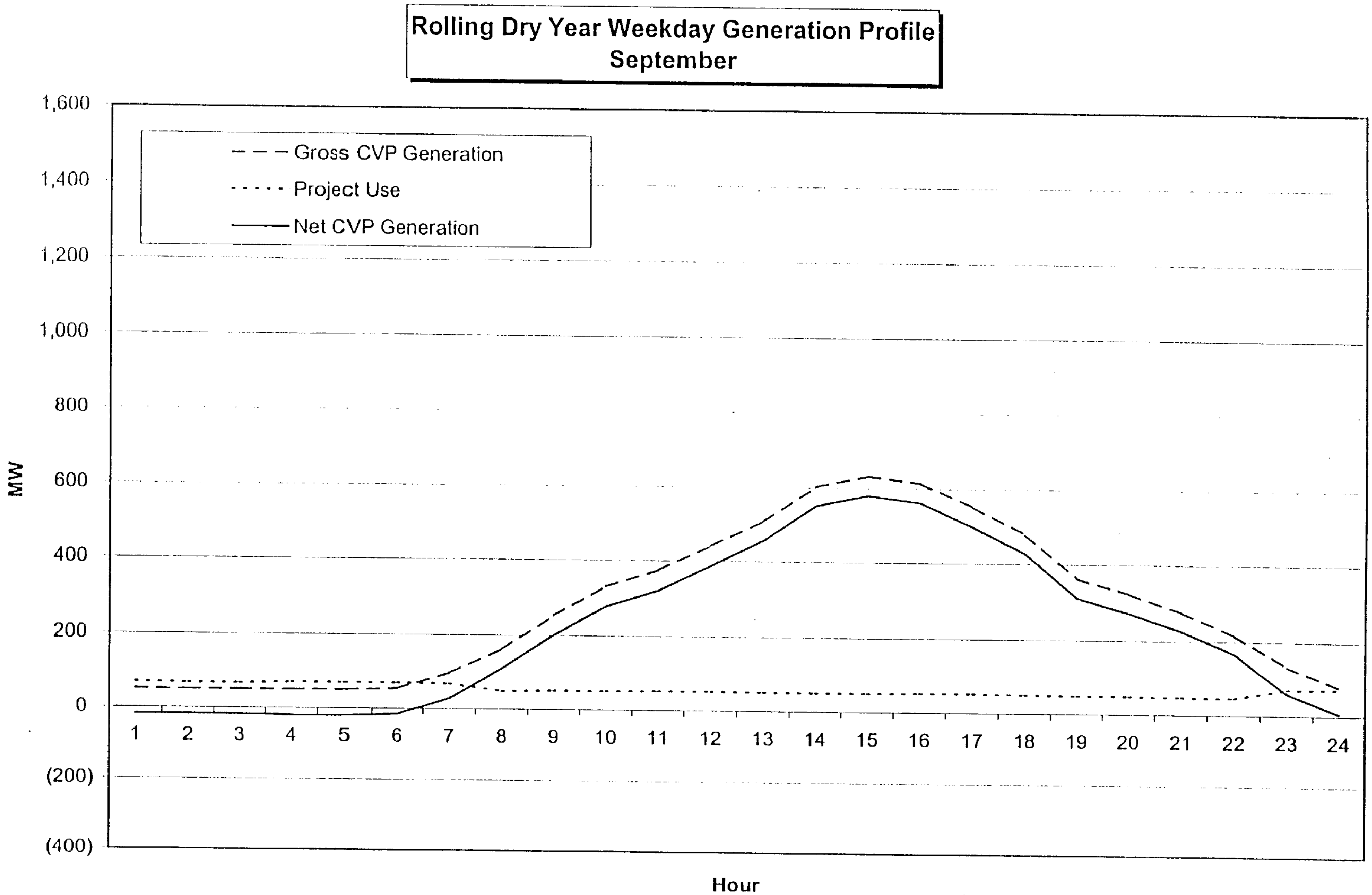
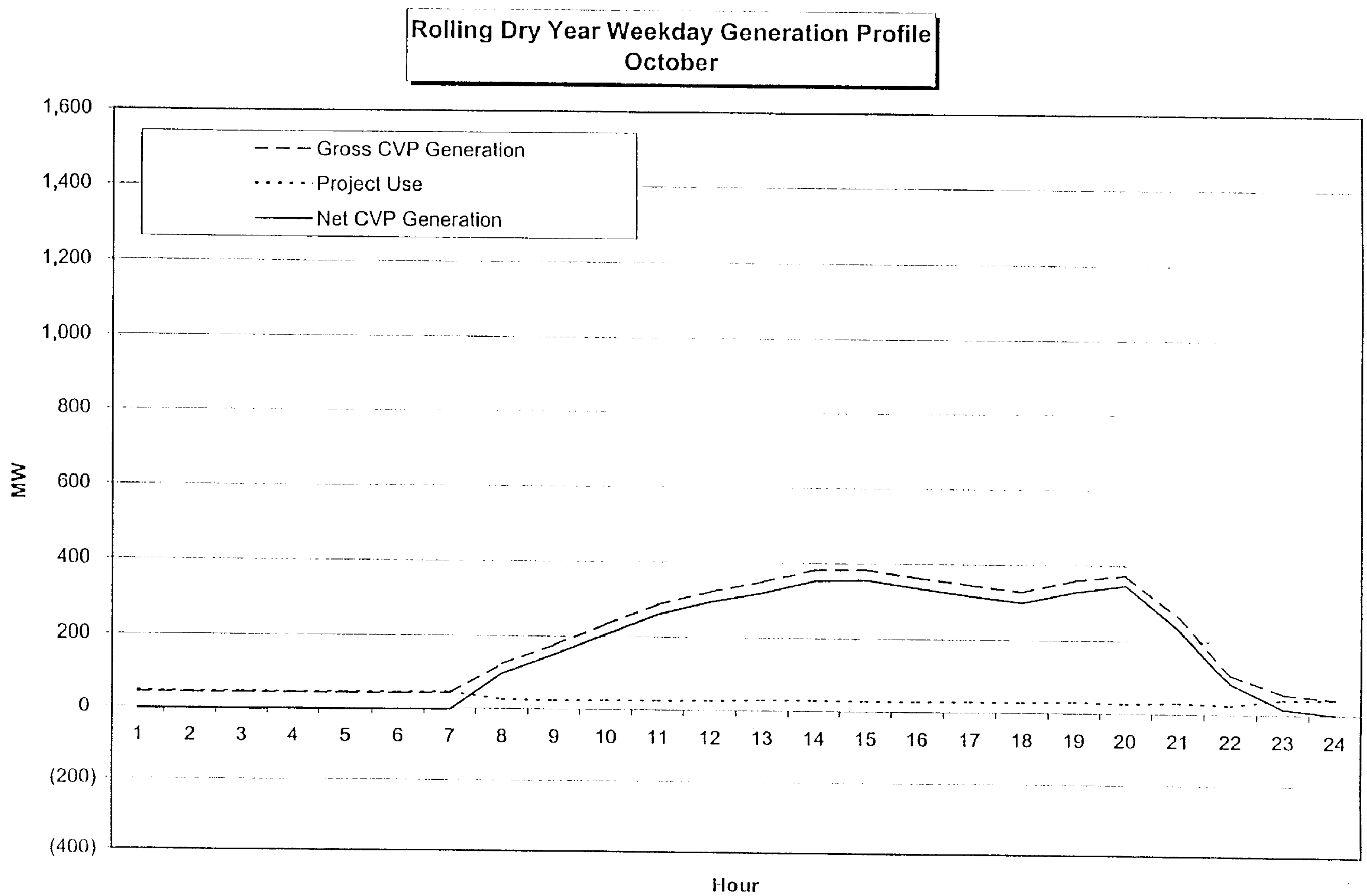


Fig. 8-9



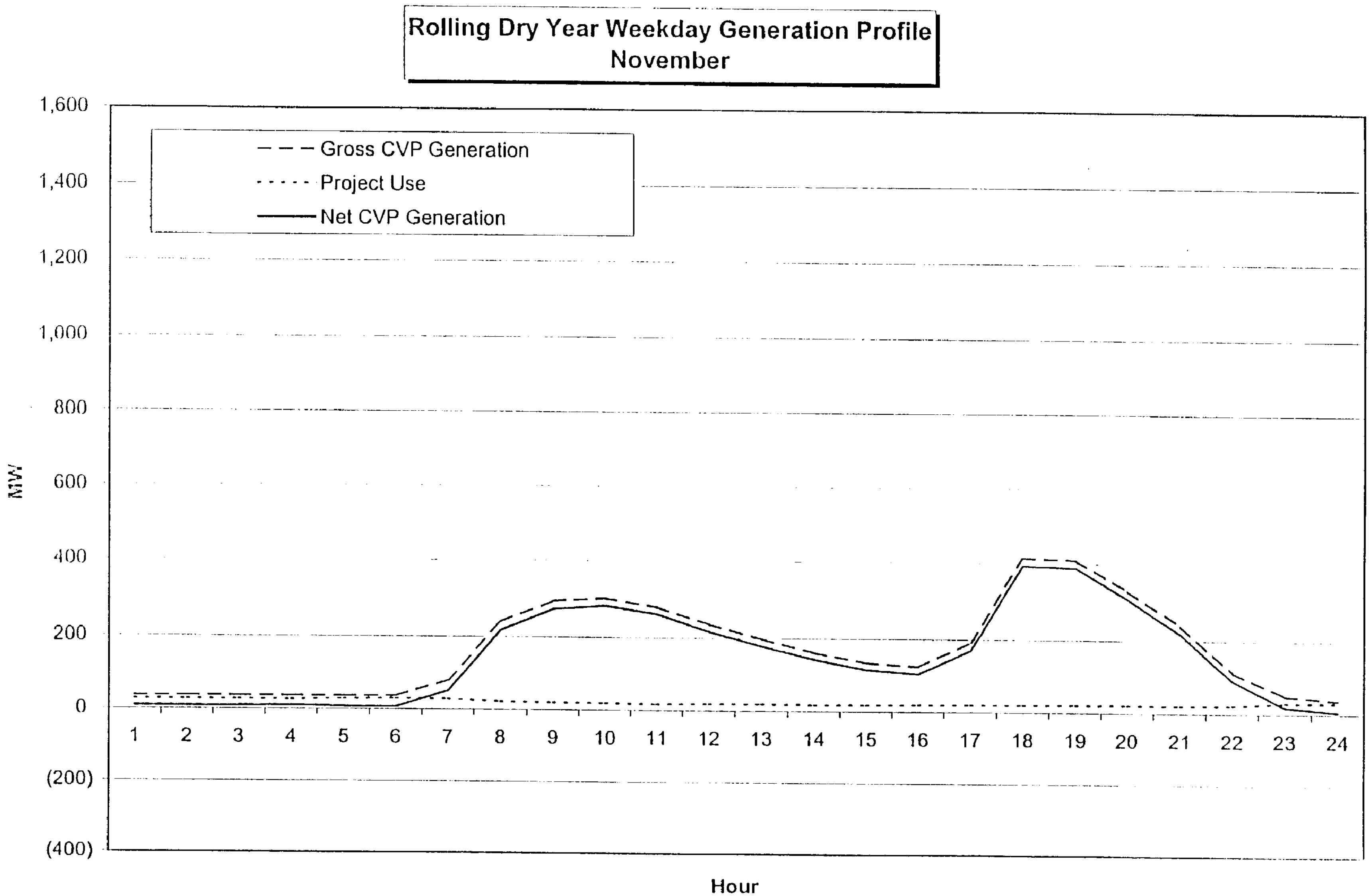
Rolling Dry Year Weekday Generation Profile
September
Gross CVP Generation
Project Use
Net CVP Generation
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
(400)
MW
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Hour

Fig 8-10



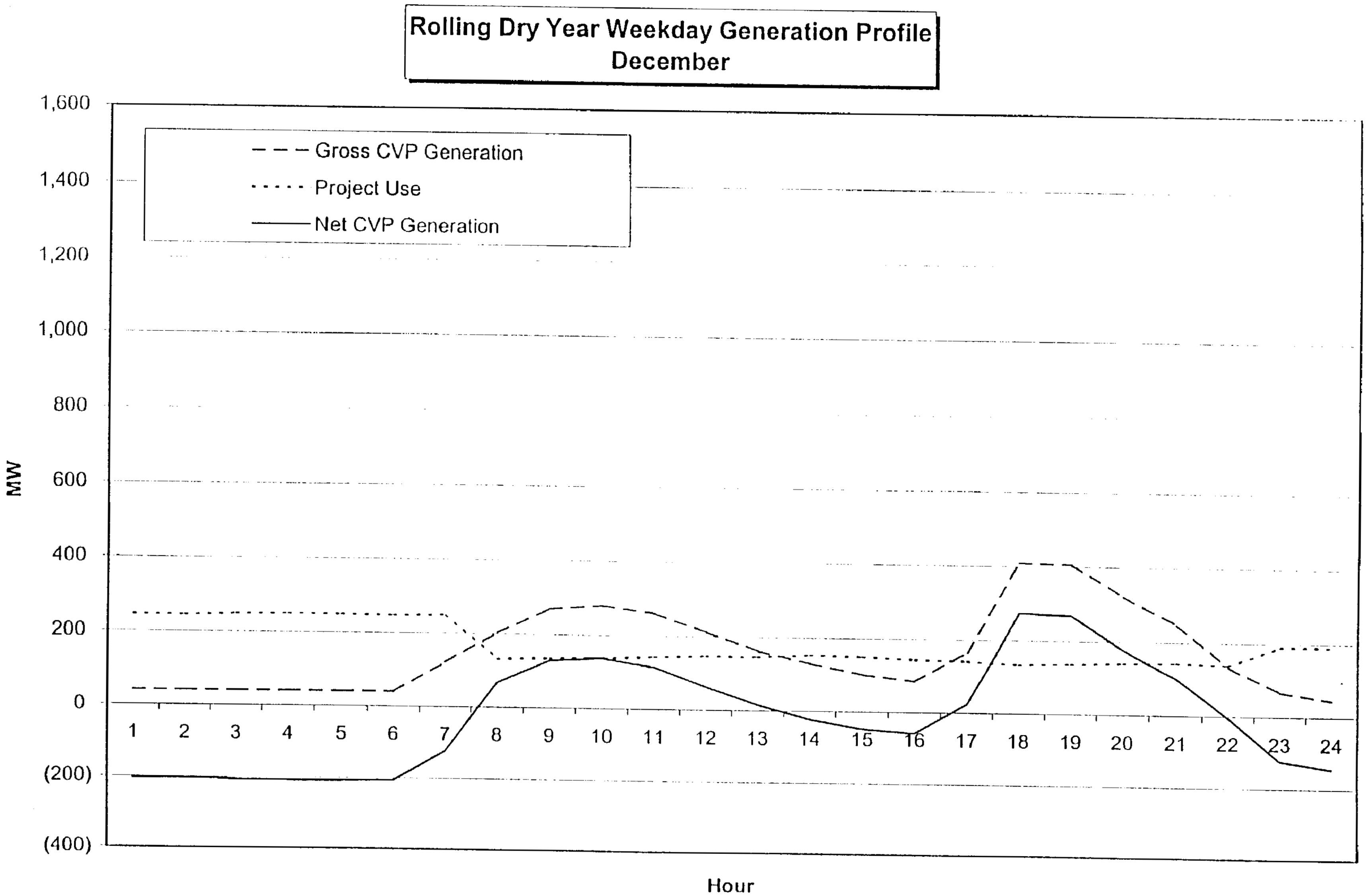
Rolling Dry Year Weekday Generation Profile
October
Gross CVP Generation
Project Use
Net CVP Generation
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
(400)
MW
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Hour

Fig. 8-11



Rolling Dry Year Weekday Generation Profile
November
Gross CVP Generation
Project Use
Net CVP Generation
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
(400)
MW
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Hour

Fig. 8·12



Rolling Dry Year Weekday Generation Profile
December
Gross CVP Generation
Project Use
Net CVP Generation
MW
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
(400)
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

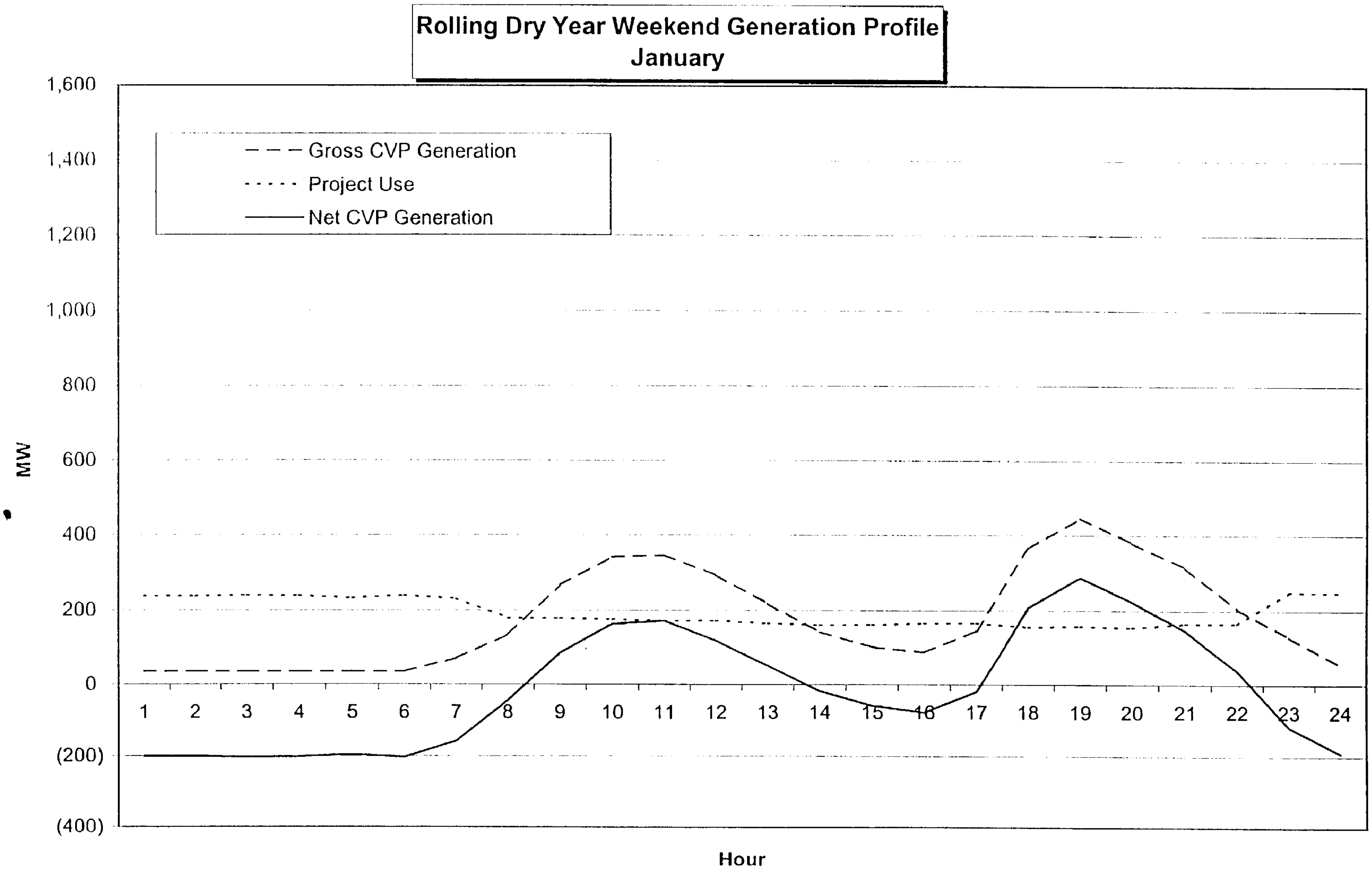
Daily Generation Profile

Dry Year Generation

Average Weekend

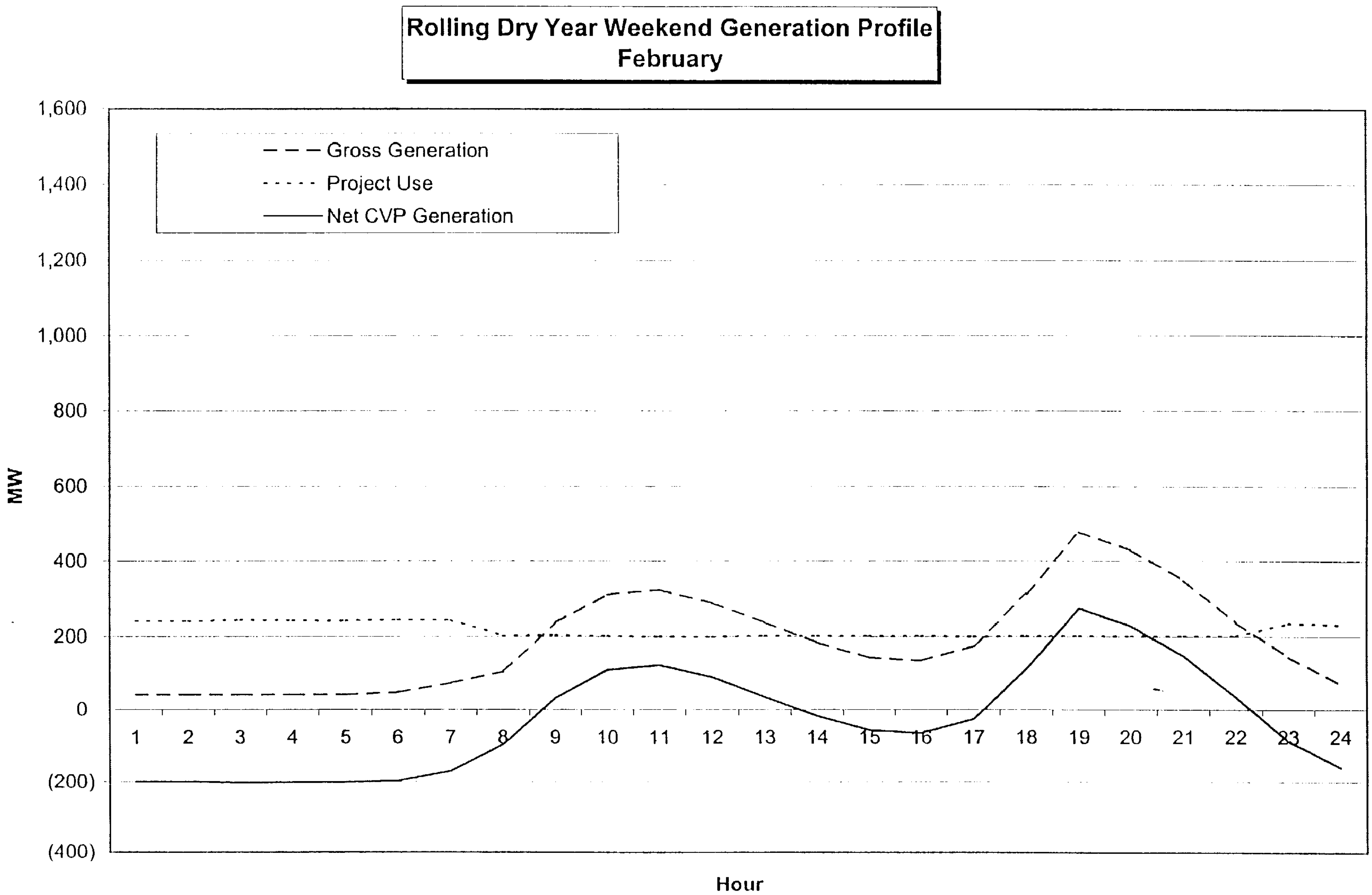
Figures 9-1 thru 9-12

Fig. 9-1



Rolling Dry Year Weekend Generation Profile
January
Gross CVP Generation
Project Use
Net CVP Generation
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
(400)
MW
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Hour

Fig. 9-2



Rolling Dry Year Weekend Generation Profile
February
Gross Generation
Project Use
Net CVP Generation
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
(400)
MW
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Hour

Fig. 9-3

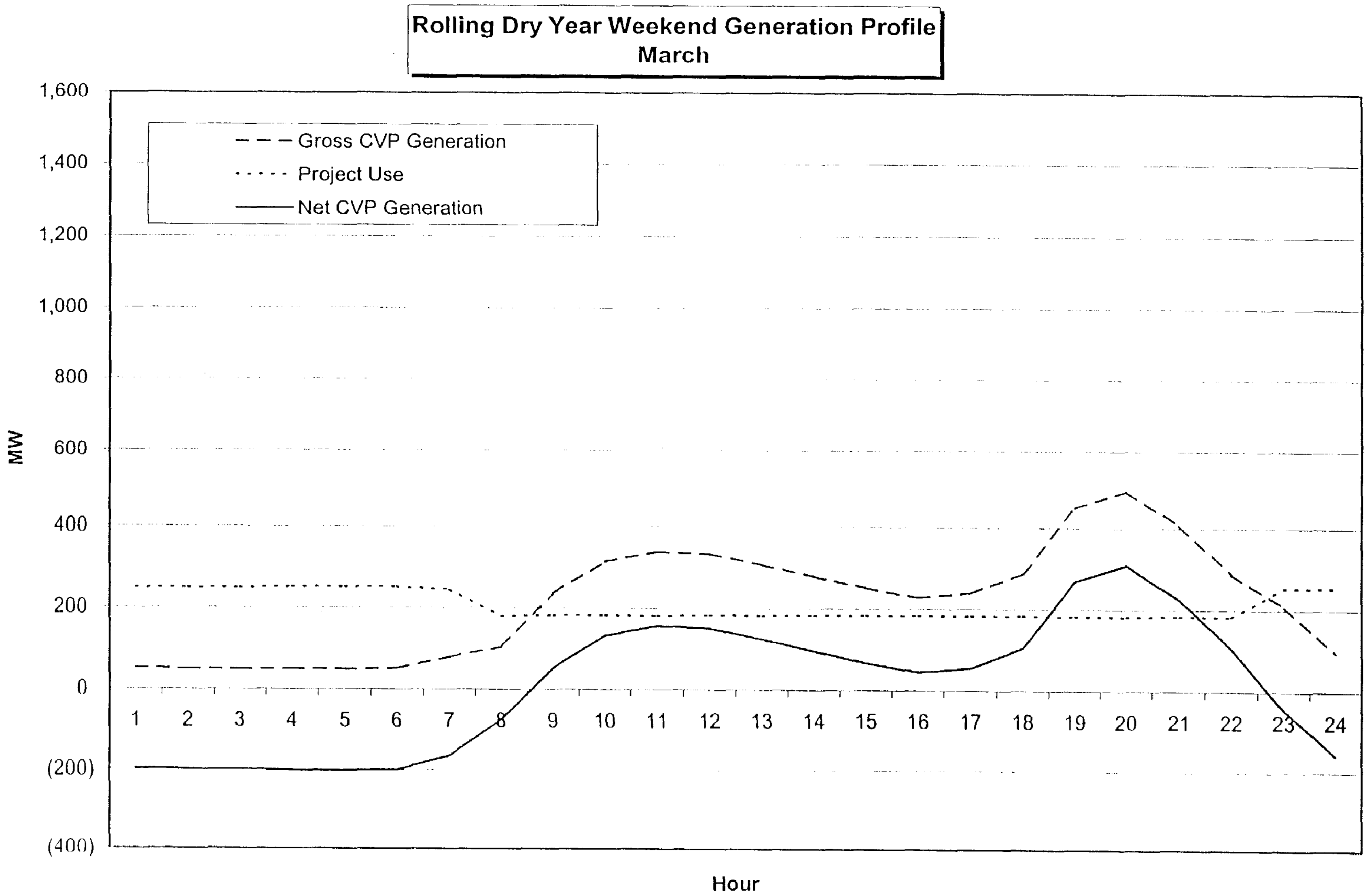

Rolling Dry Year Weekend Generation Profile
March
Gross CVP Generation
Project Use
Net CVP Generation
MW
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
(400)
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Hour

Fig 9-4

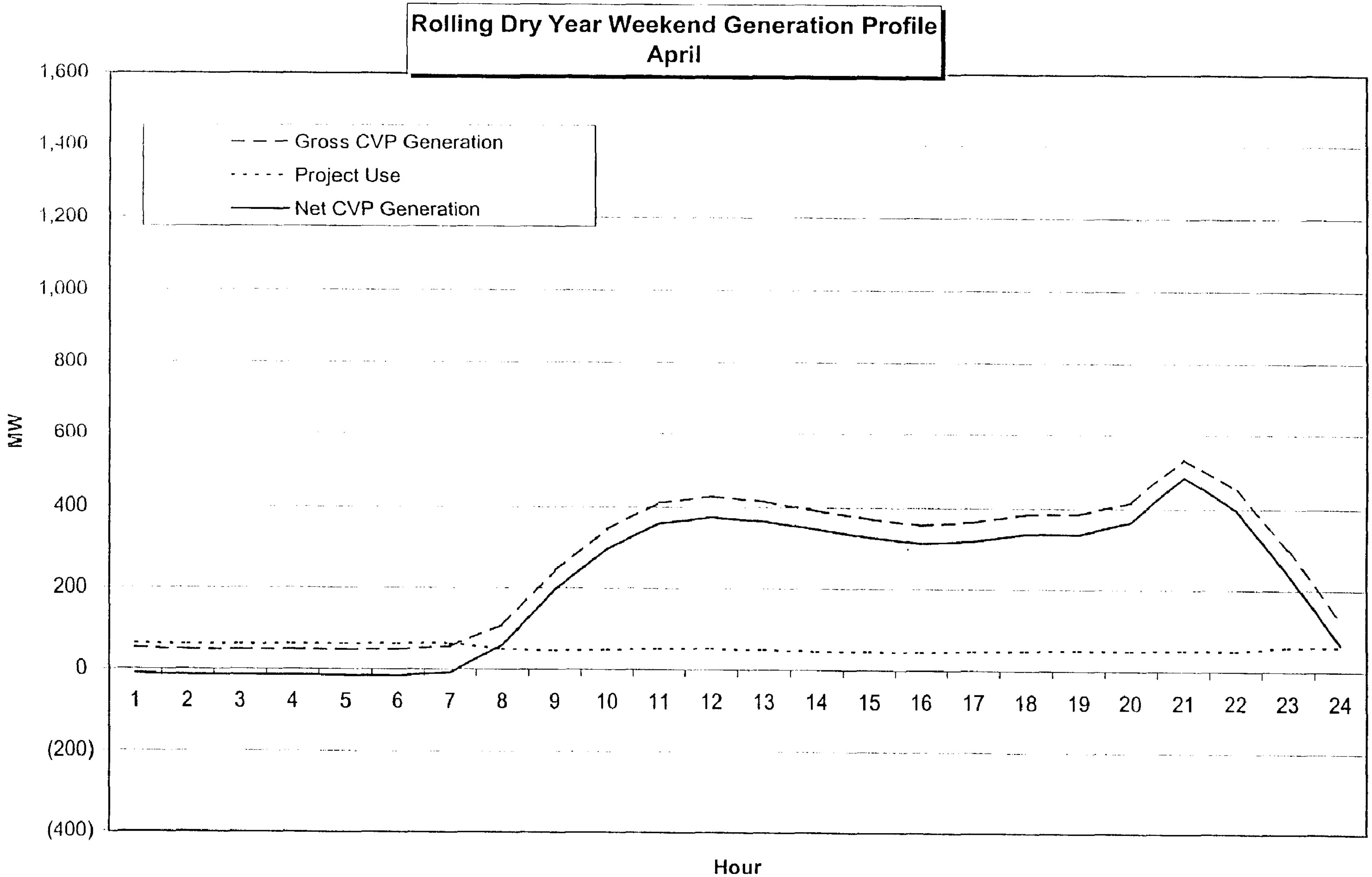

Rolling Dry Year Weekend Generation Profile
April
Gross CVP Generation
Project Use
Net CVP Generation
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
(400)
MW
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Hour

Fig. 9-5

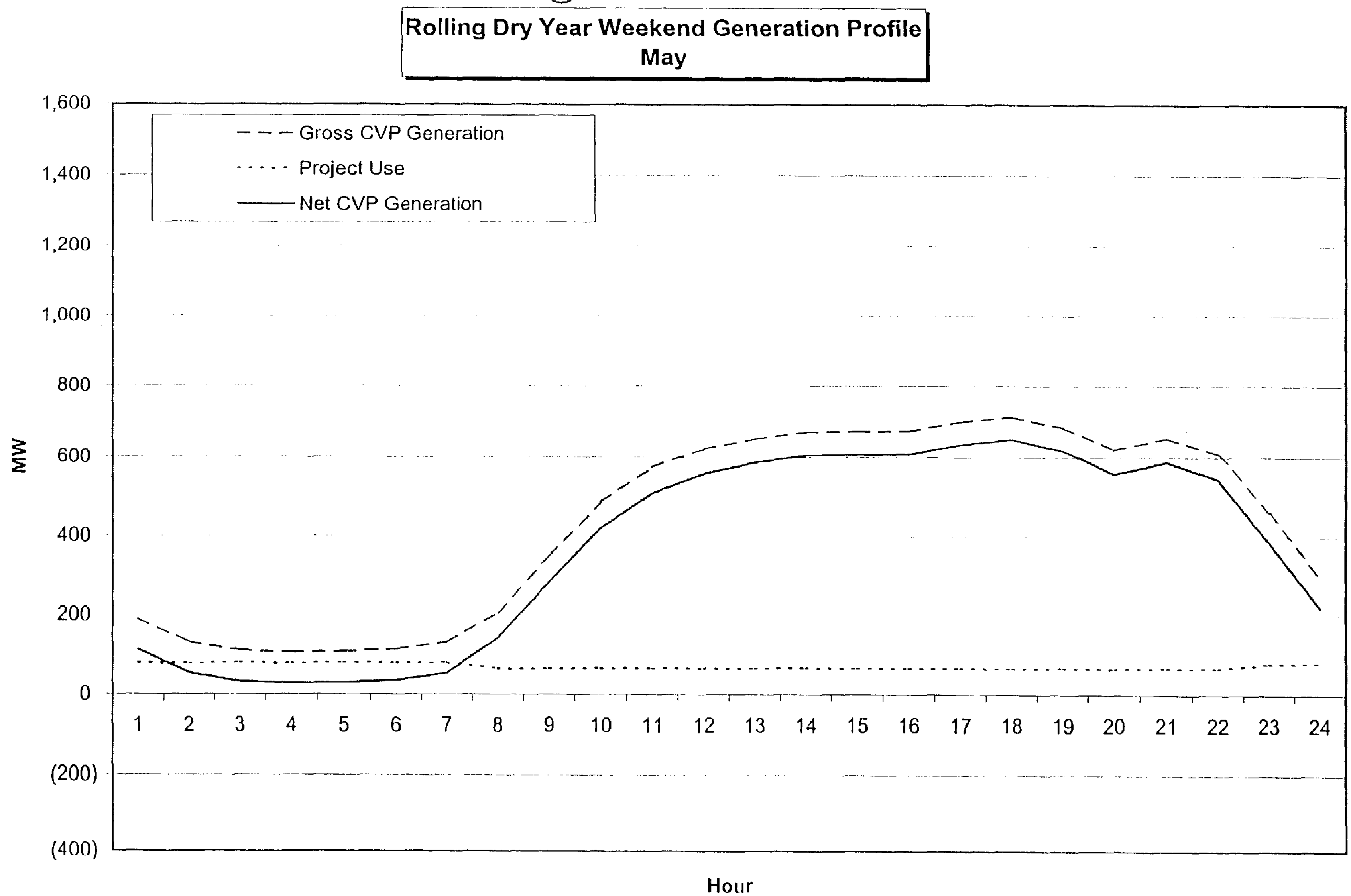

Rolling Dry Year Weekend Generation Profile
May
Gross CVP Generation
Project Use
Net CVP Generation
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
(400)
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

Fig 9-6

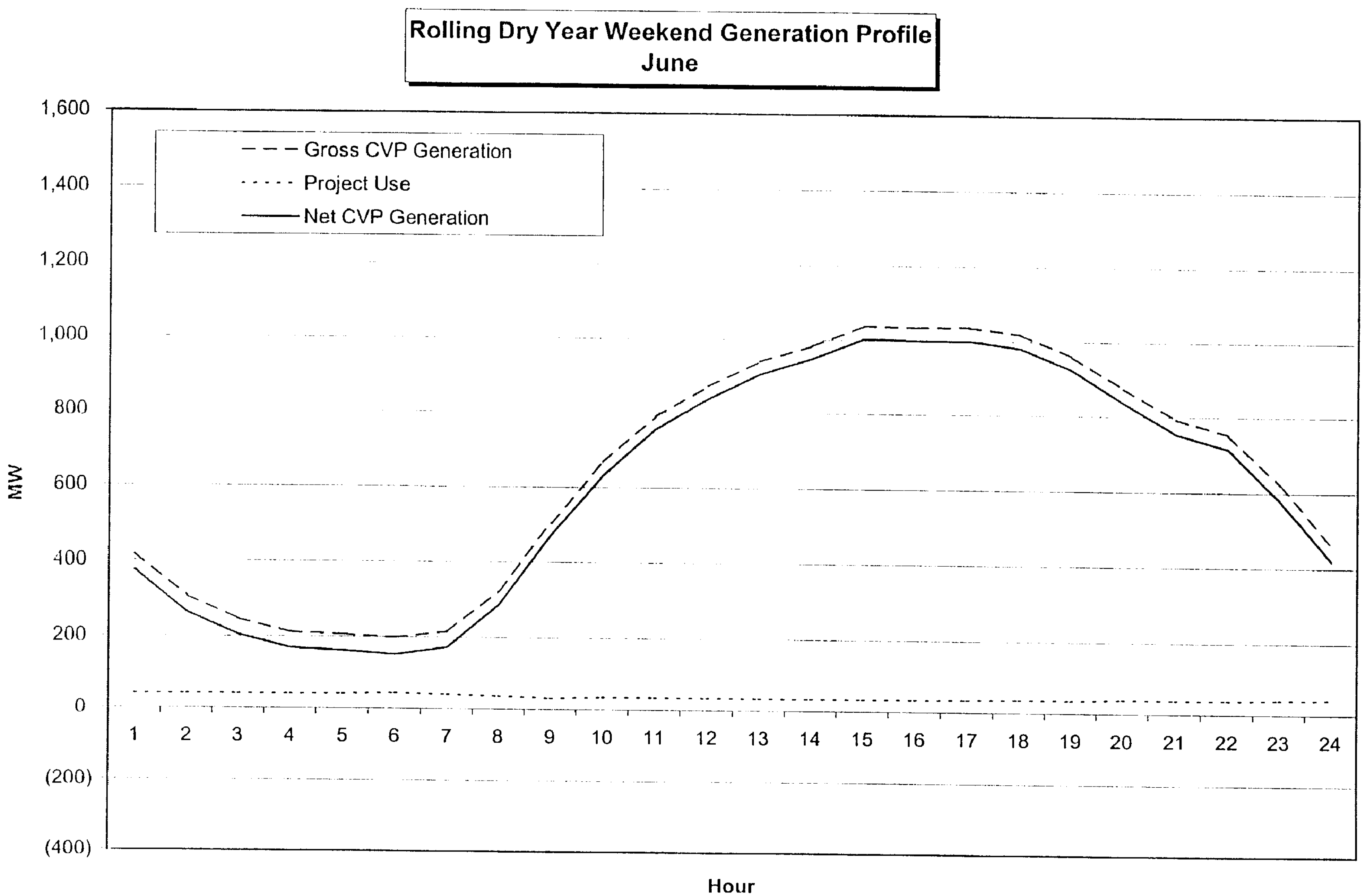
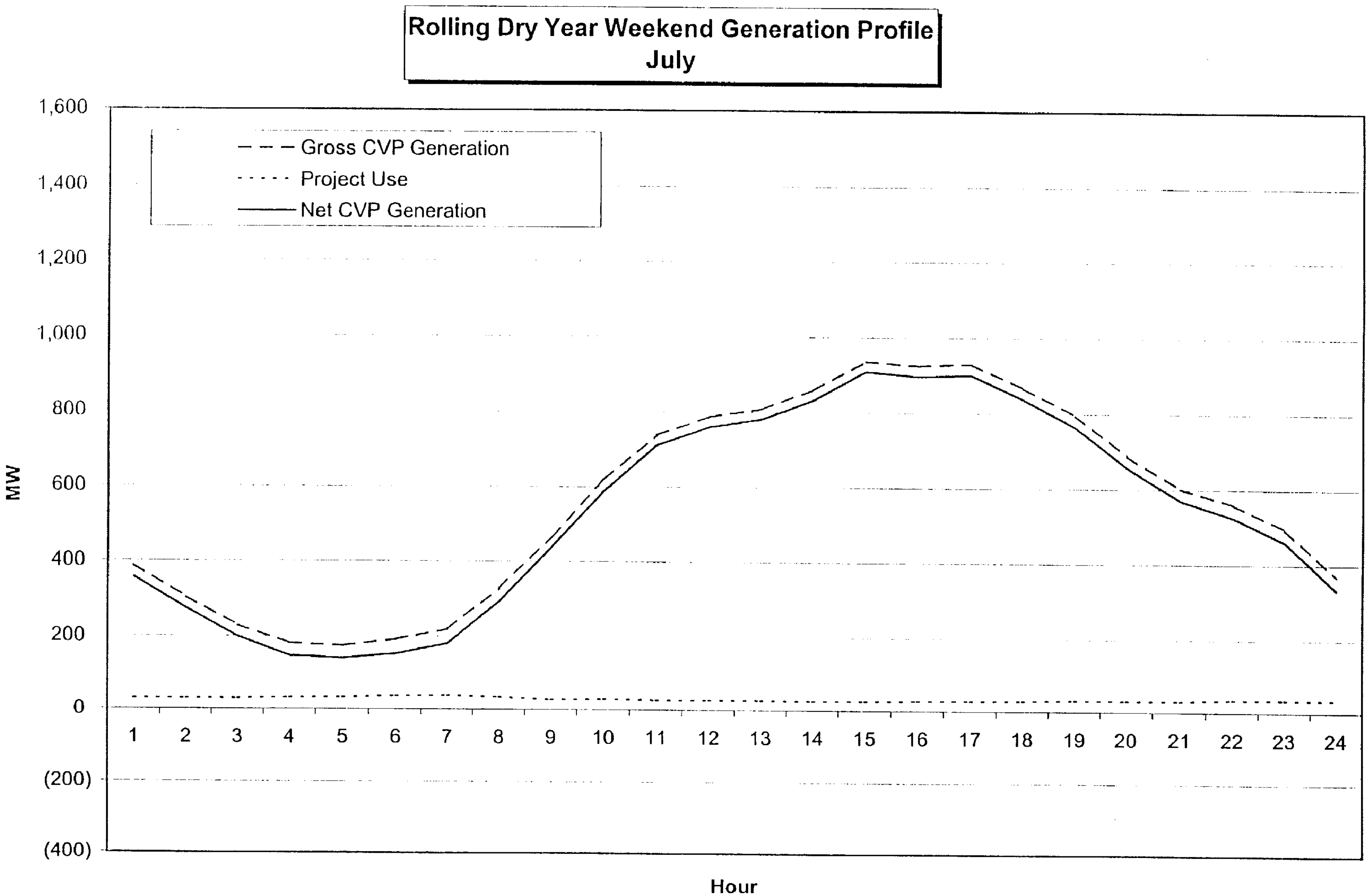
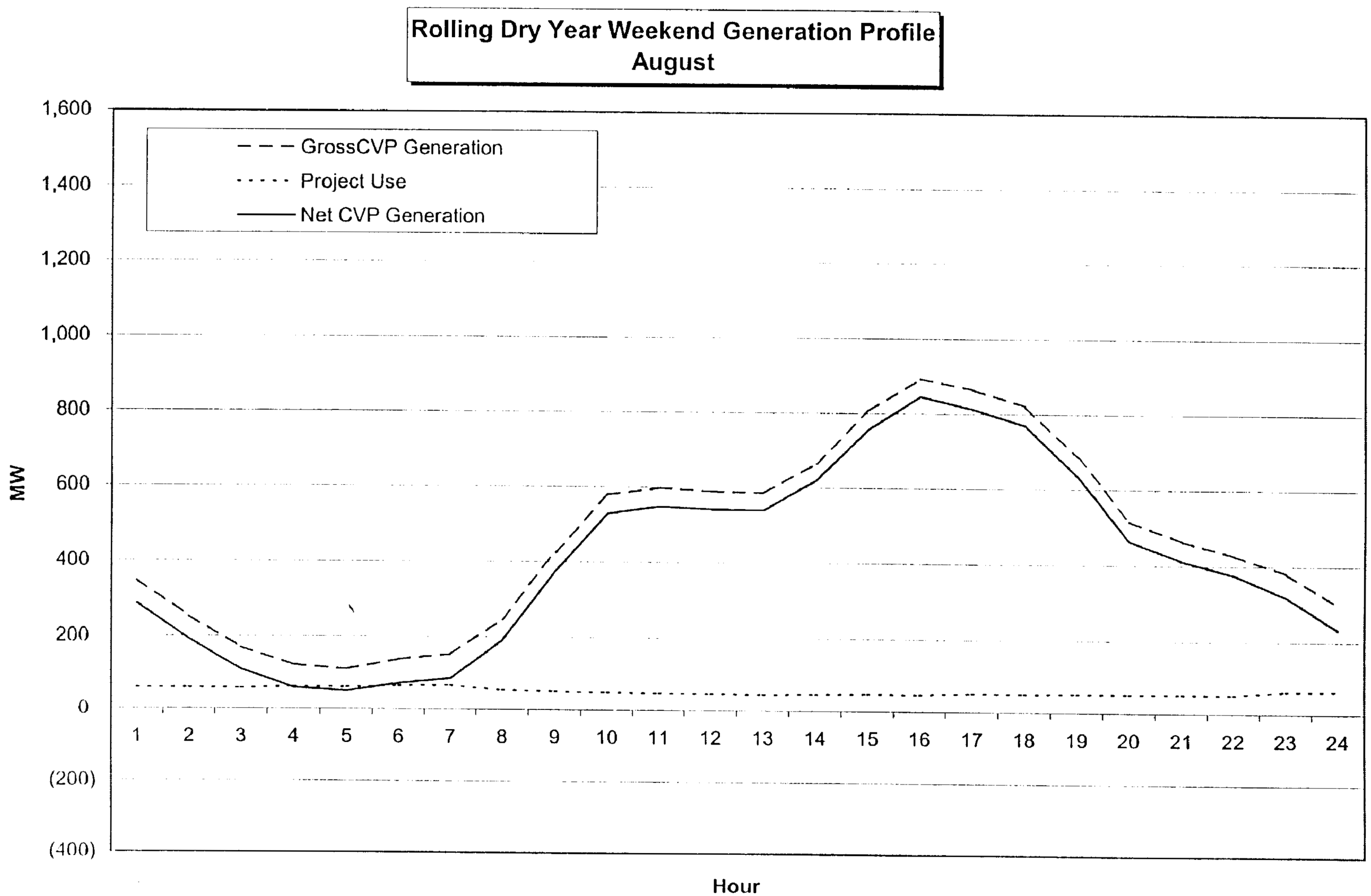

Rolling Dry Year Weekend Generation Profile
June
Gross CVP Generation
Project Use
Net CVP Generation
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
(400)
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

Fig 9-7



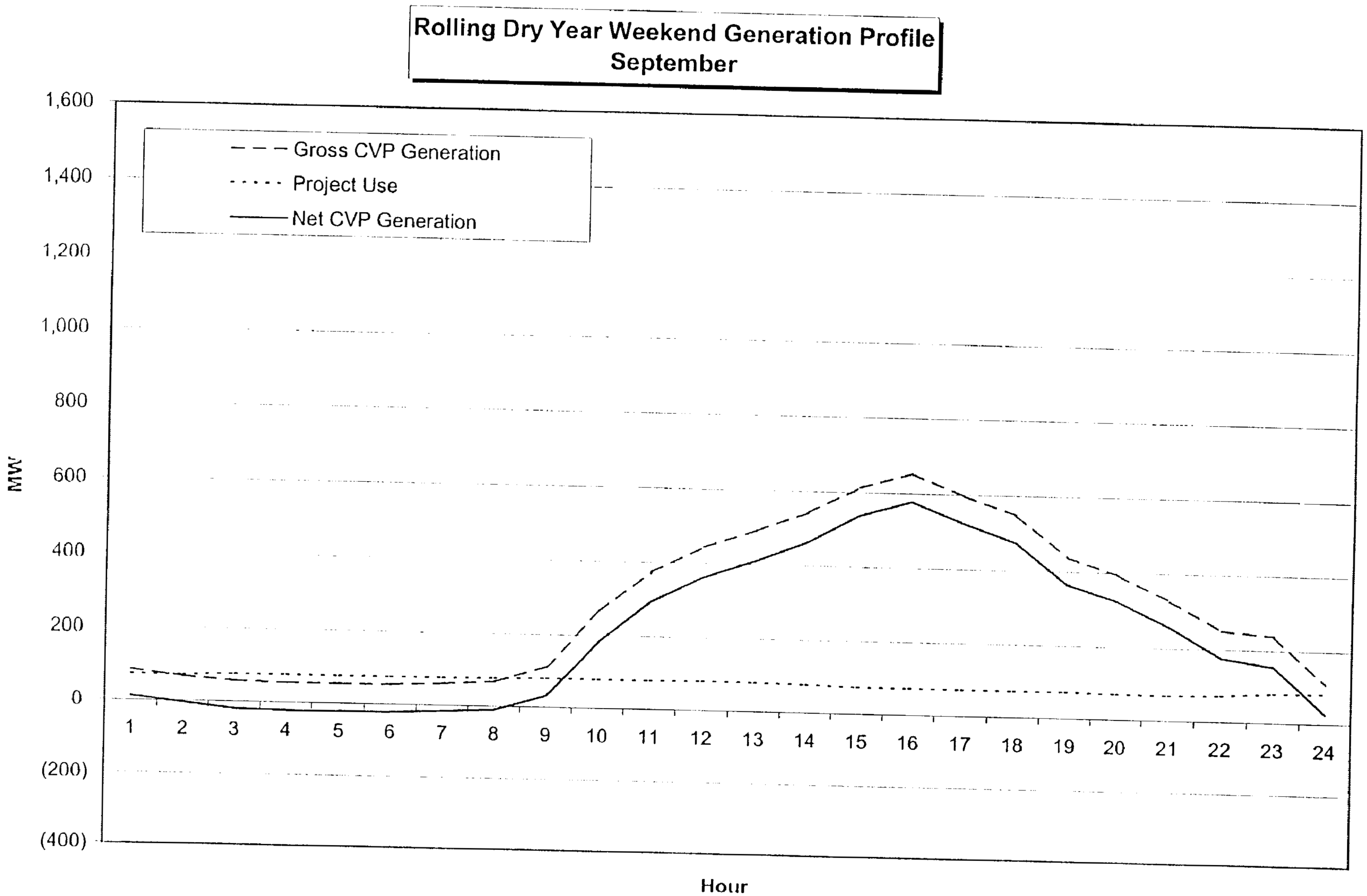
Rolling Dry Year Weekend Generation Profile
July
Gross CVP Generation
Project Use
Net CVP Generation
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
(400)
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

Fig. 9-8



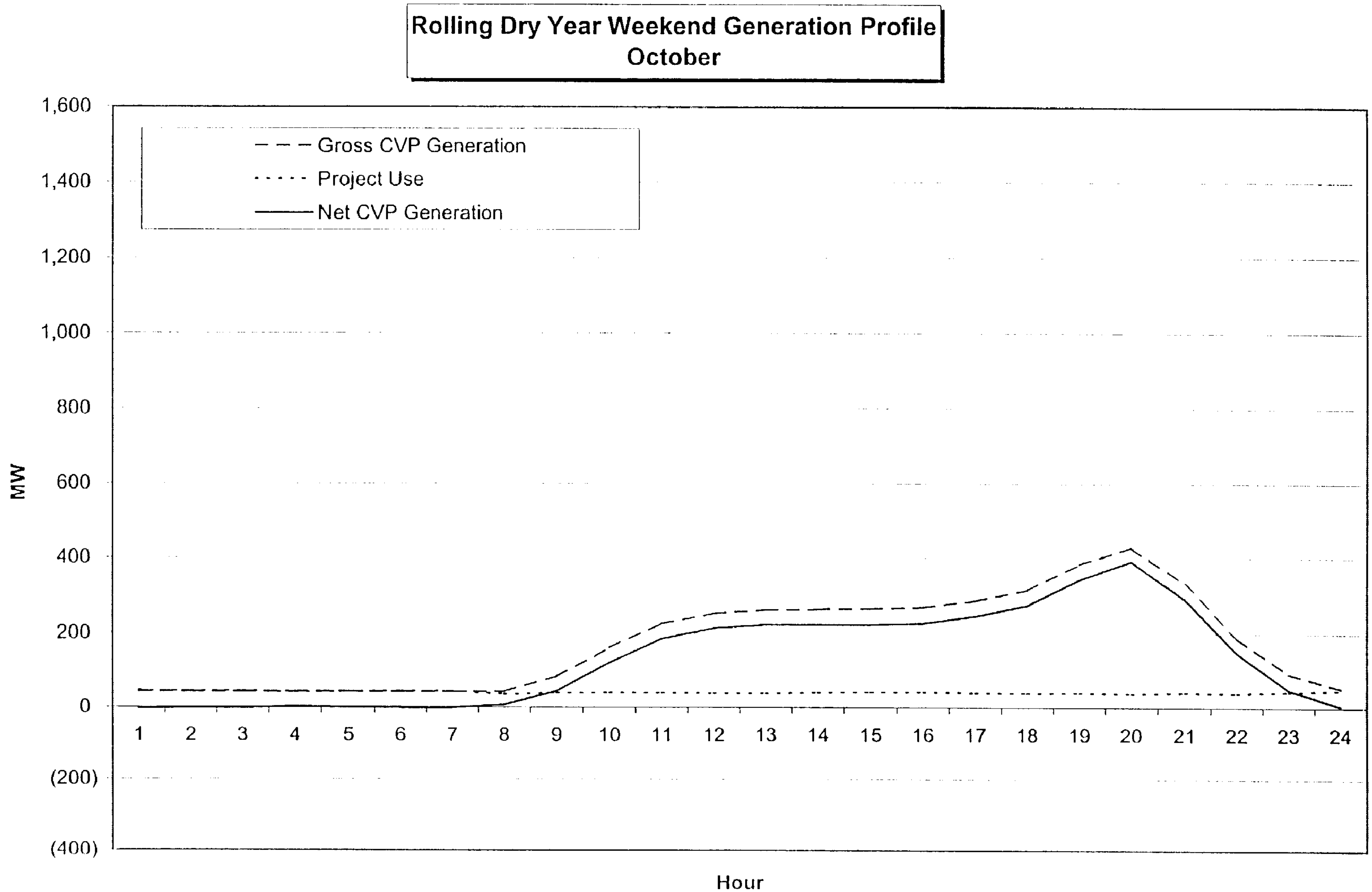
Rolling Dry Year Weekend Generation Profile
August
GrossCVP Generation
Project Use
Net CVP Generation
MW
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
(400)
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

Fig. 9-9



Rolling Dry Year Weekend Generation Profile
September
Gross CVP Generation
Project Use
Net CVP Generation
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
(400)
MW
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Hour

Fig. 9-10



Rolling Dry Year Weekend Generation Profile
October
Gross CVP Generation
Project Use
Net CVP Generation
MW
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
(400)
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Hour

Fig. 9-11

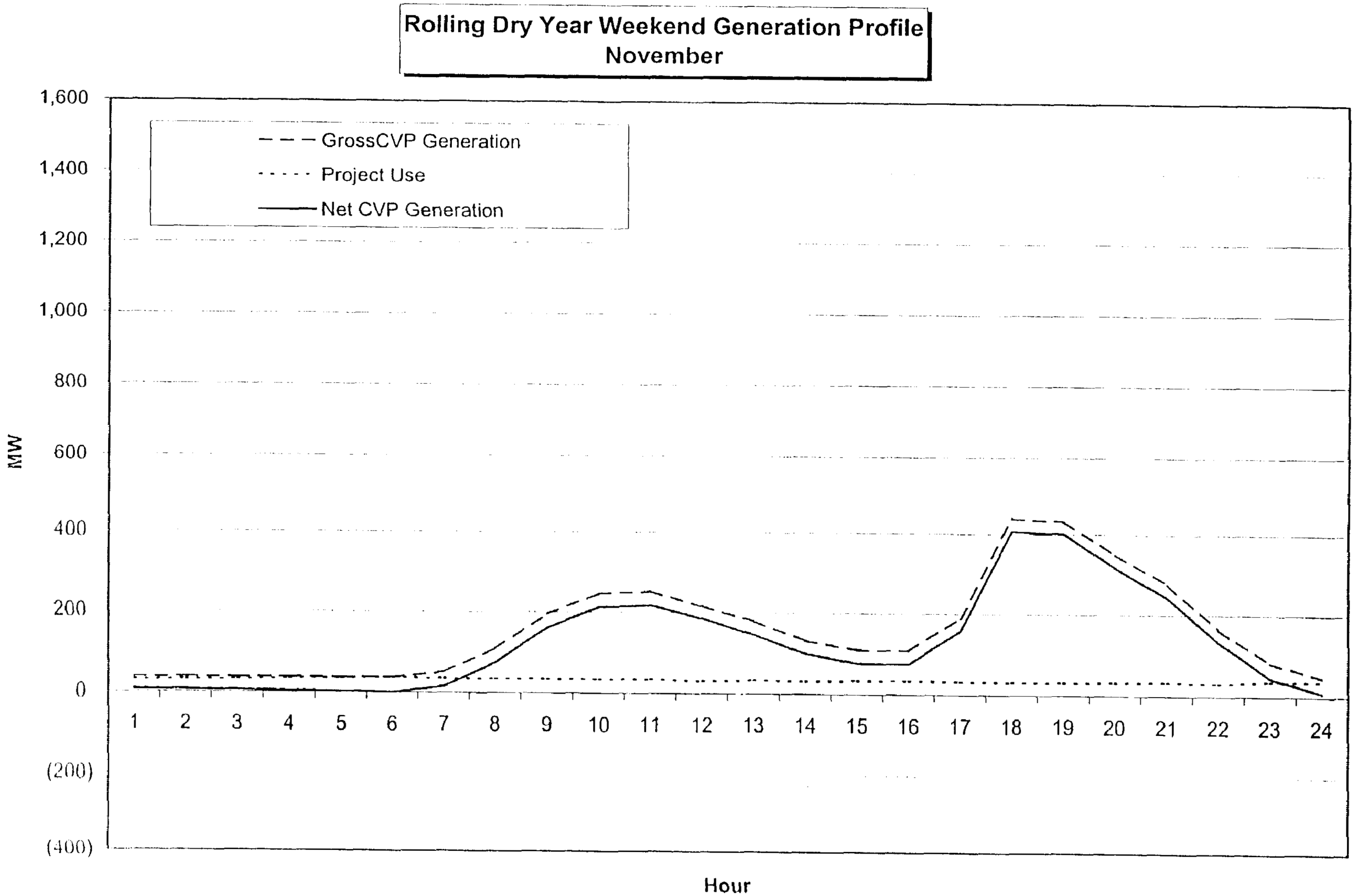
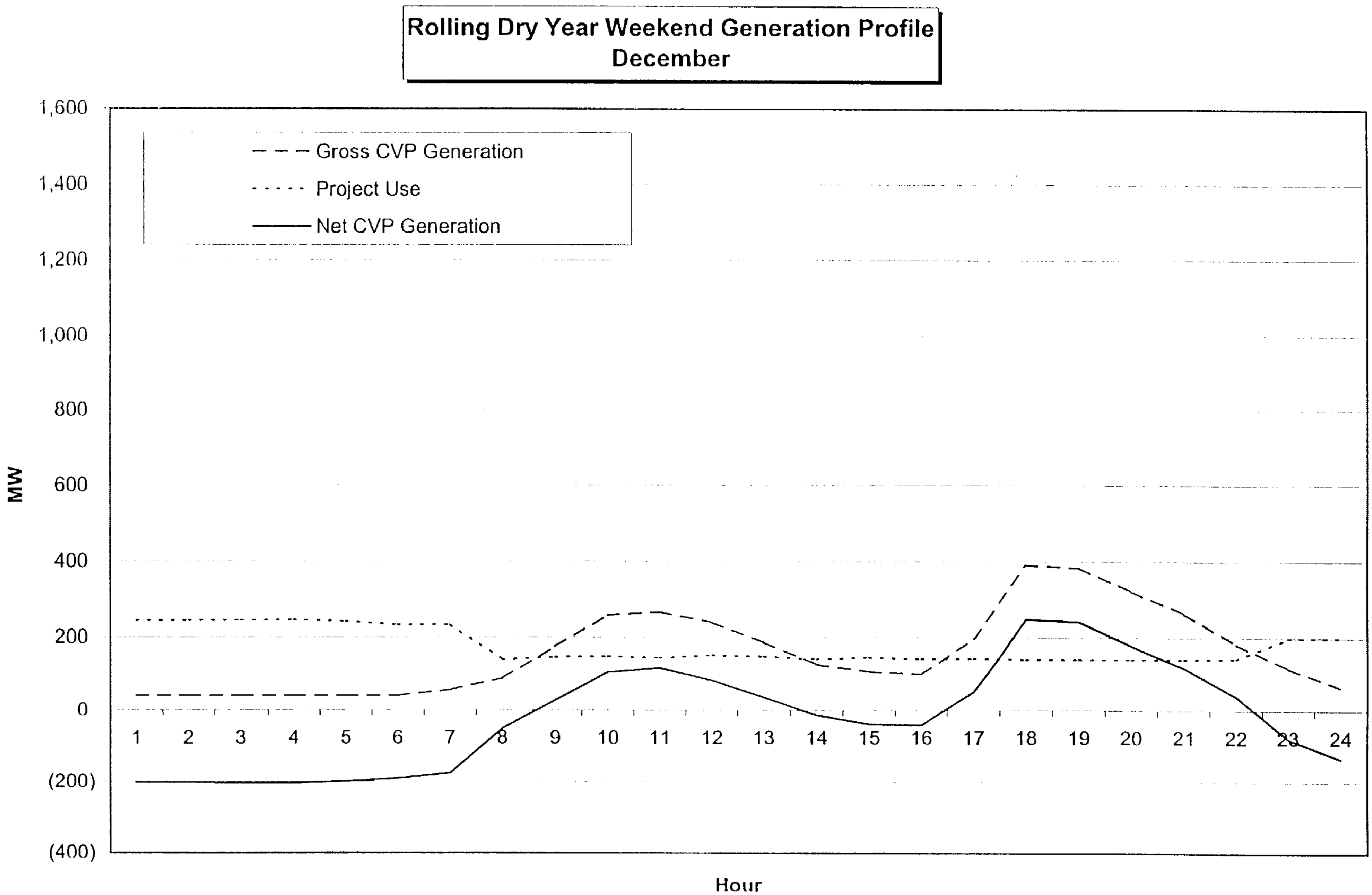

Rolling Dry Year Weekend Generation Profile
November
GrossCVP Generation
Project Use
Net CVP Generation
MW
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
(400)
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

Fig. 9-12


Rolling Dry Year Weekend Generation Profile
December
Gross CVP Generation
Project Use
Net CVP Generation
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
(400)
MW
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Hour

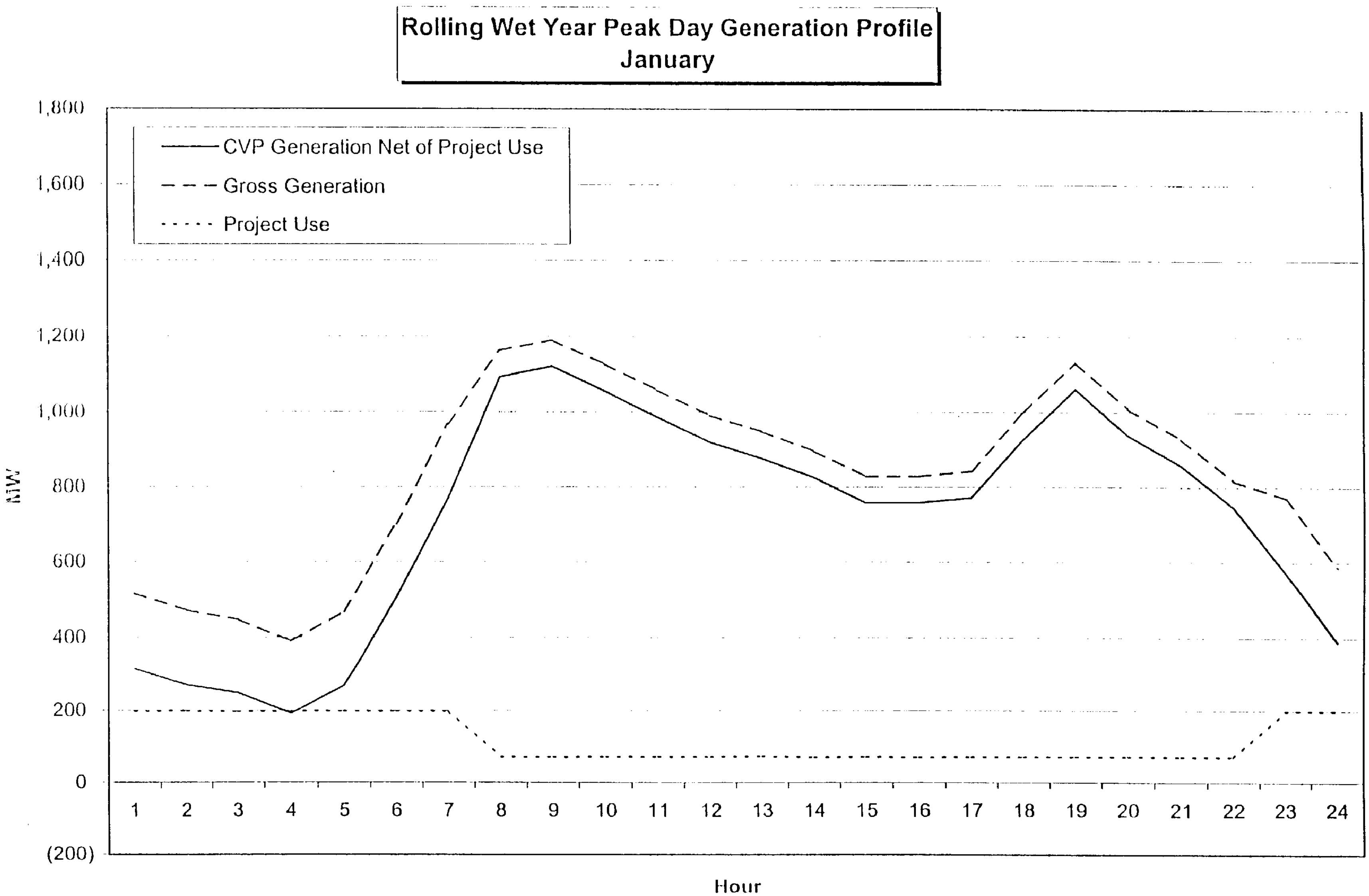
Daily Generation Profile

Wet Year Generation

Peak Weekday

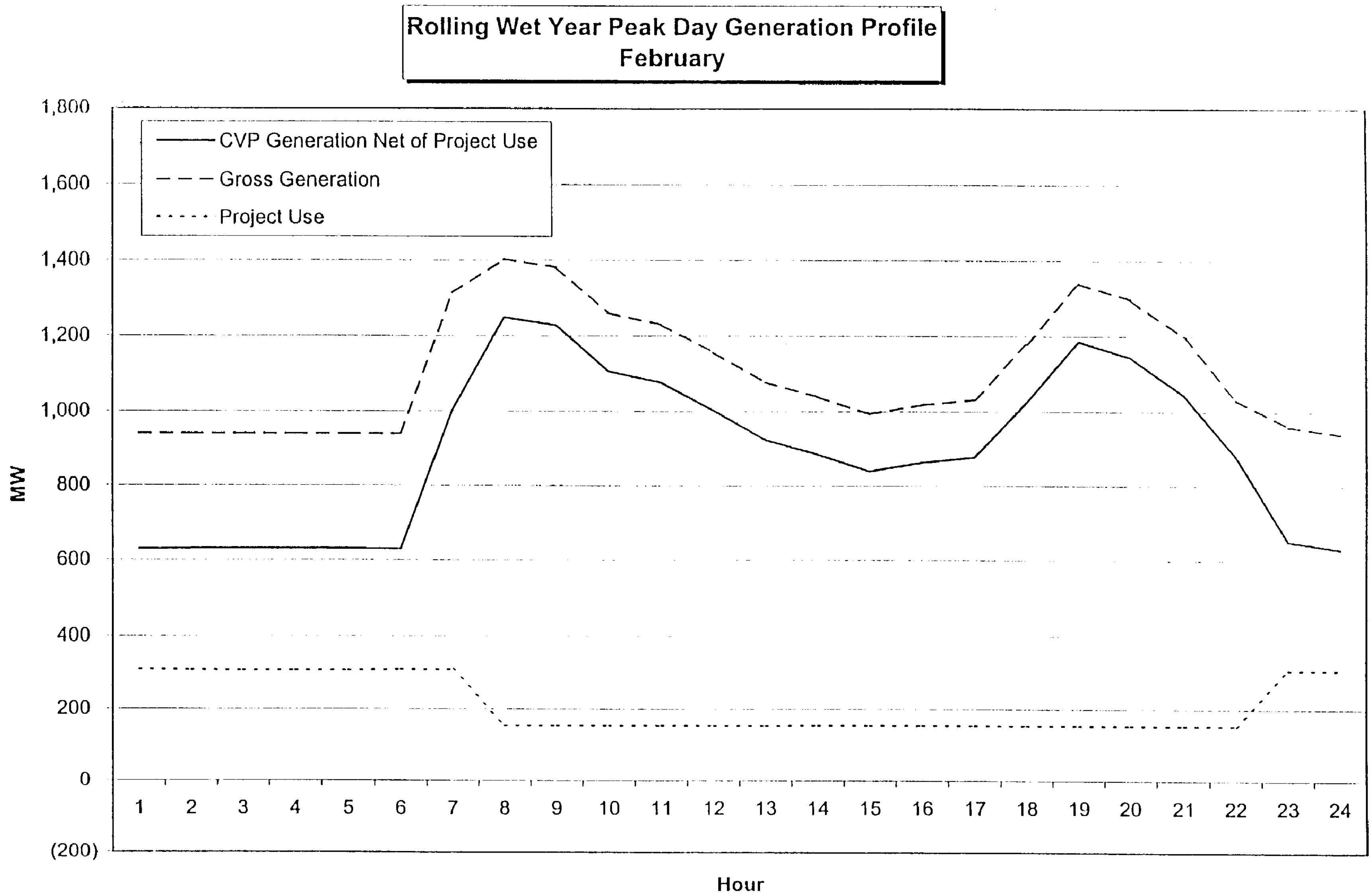
Figures 10-1 thru 10-12

Fig. 10-1



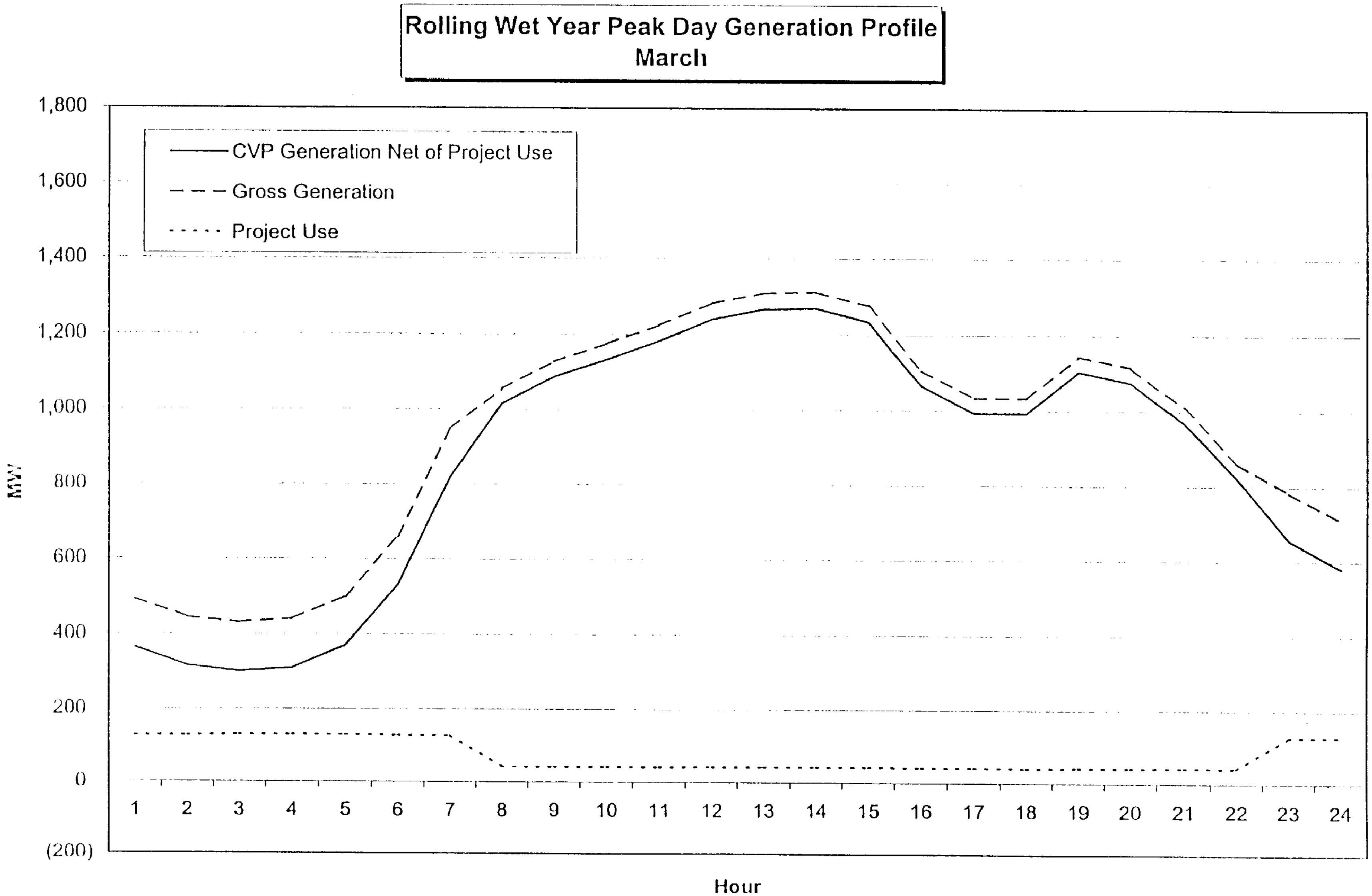
Rolling Wet Year Peak Day Generation Profile
January
CVP Generation Net of Project Use
Gross Generation
Project Use
1,800
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

Fig. 10-2



Rolling Wet Year Peak Day Generation Profile
February
CVP Generation Net of Project Use
Gross Generation
Project Use
1,800
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

Fig. 10-3



Rolling Wet Year Peak Day Generation Profile
March
CVP Generation Net of Project Use
Gross Generation
Project Use
MW
1,800
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

Fig. 10-4

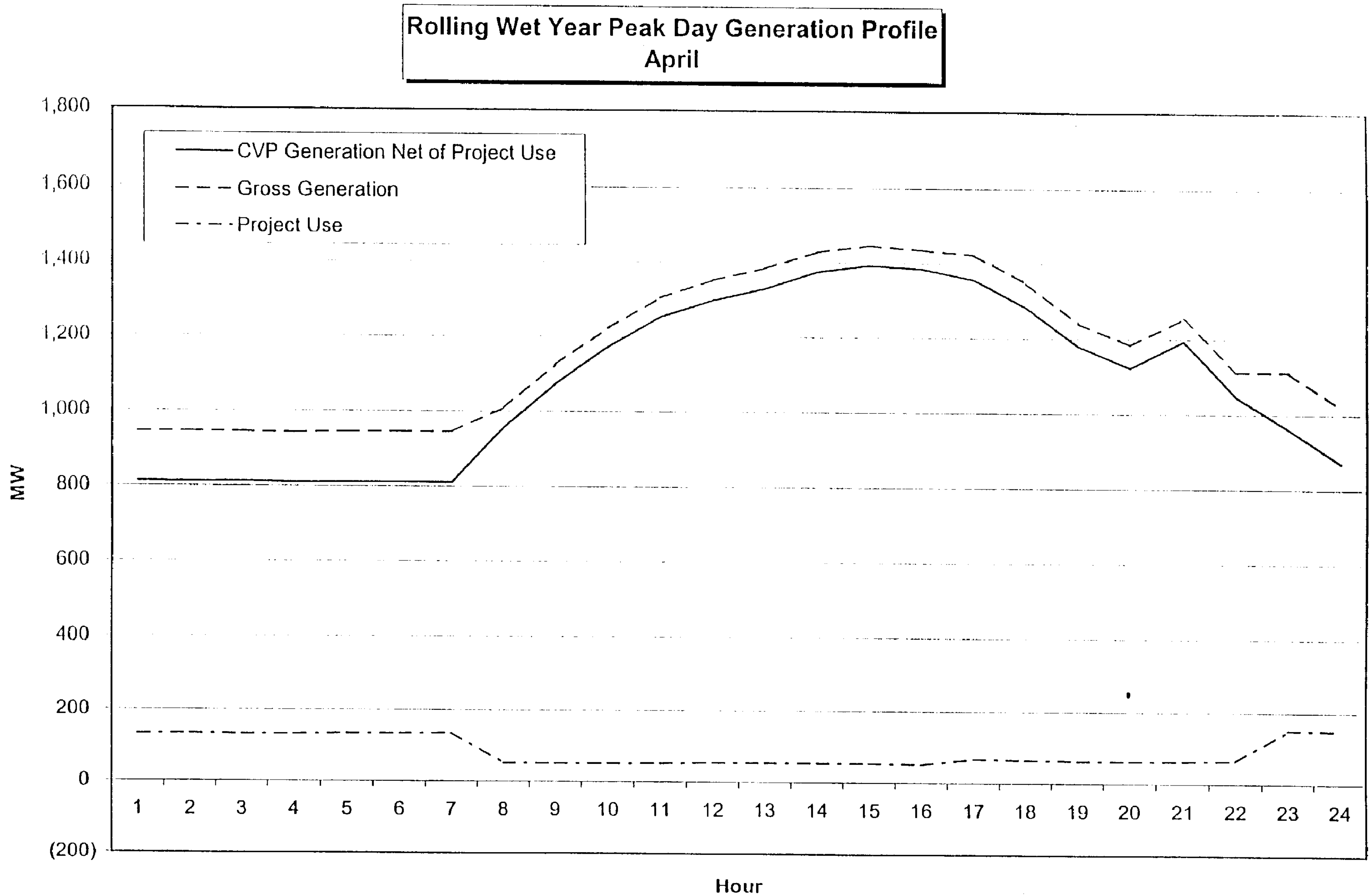
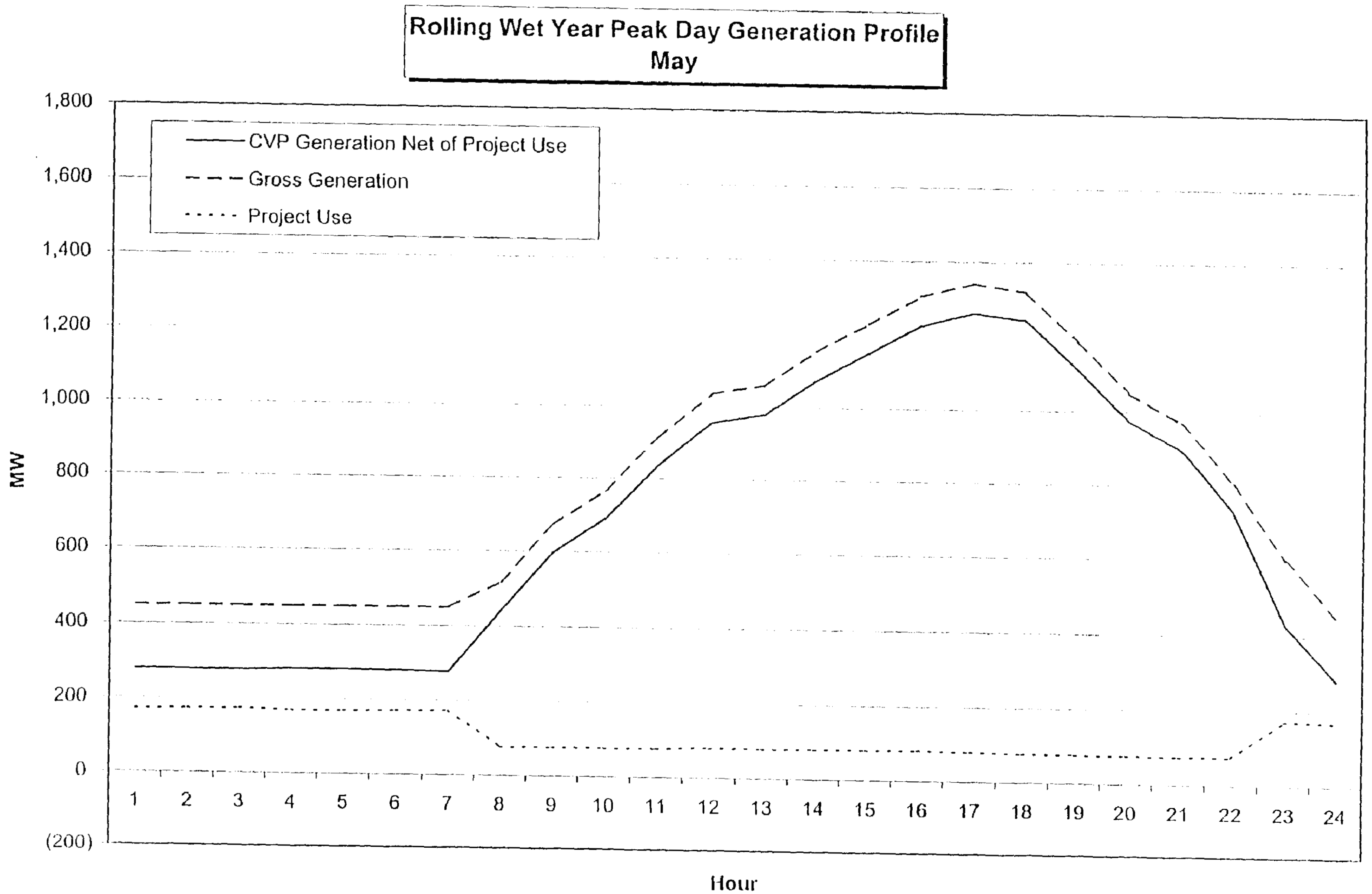
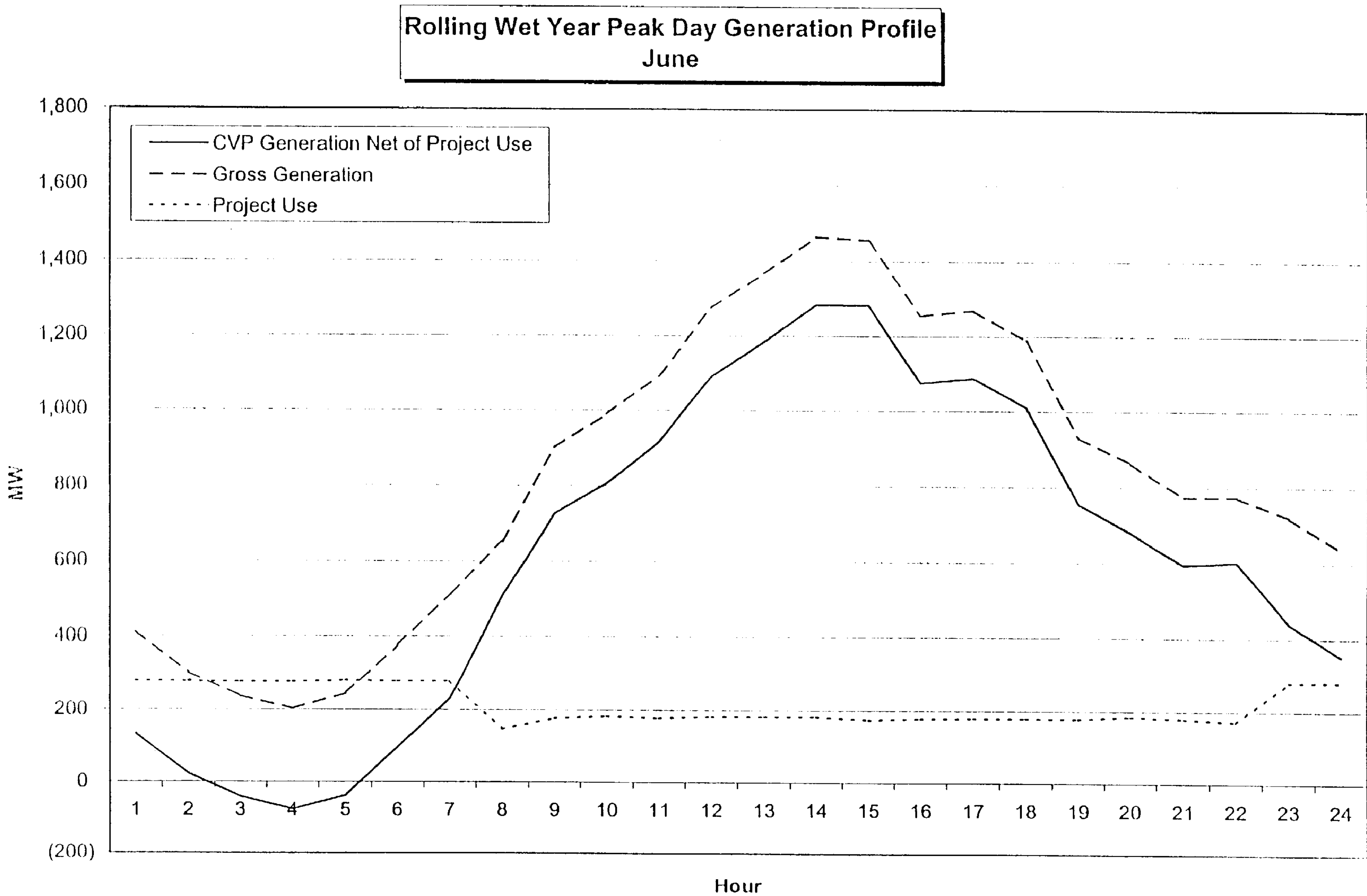

Rolling Wet Year Peak Day Generation Profile
April
CVP Generation Net of Project Use
Gross Generation
Project Use
1,800
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Hour

Fig. 10-5



Rolling Wet Year Peak Day Generation Profile
May
CVP Generation Net of Project Use
Gross Generation
Project Use
1,800
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

Fig. 10-6



Rolling Wet Year Peak Day Generation Profile
June
CVP Generation Net of Project Use
Gross Generation
Project Use
1,800
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Hour

Fig. 10-7

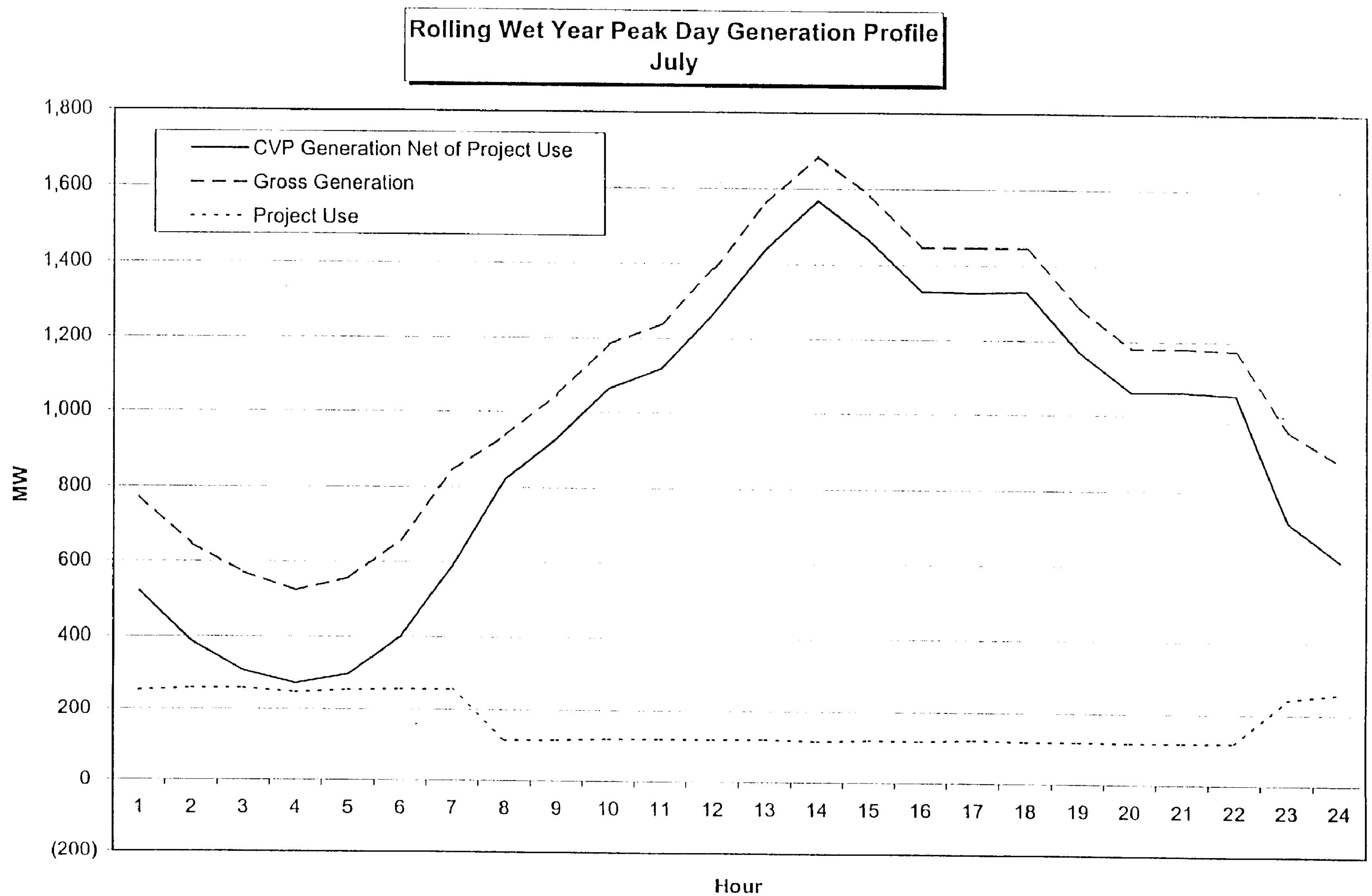

Rolling Wet Year Peak Day Generation Profile
July
CVP Generation Net of Project Use
Gross Generation
Project Use
1,800
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Hour

Fig. 10-8

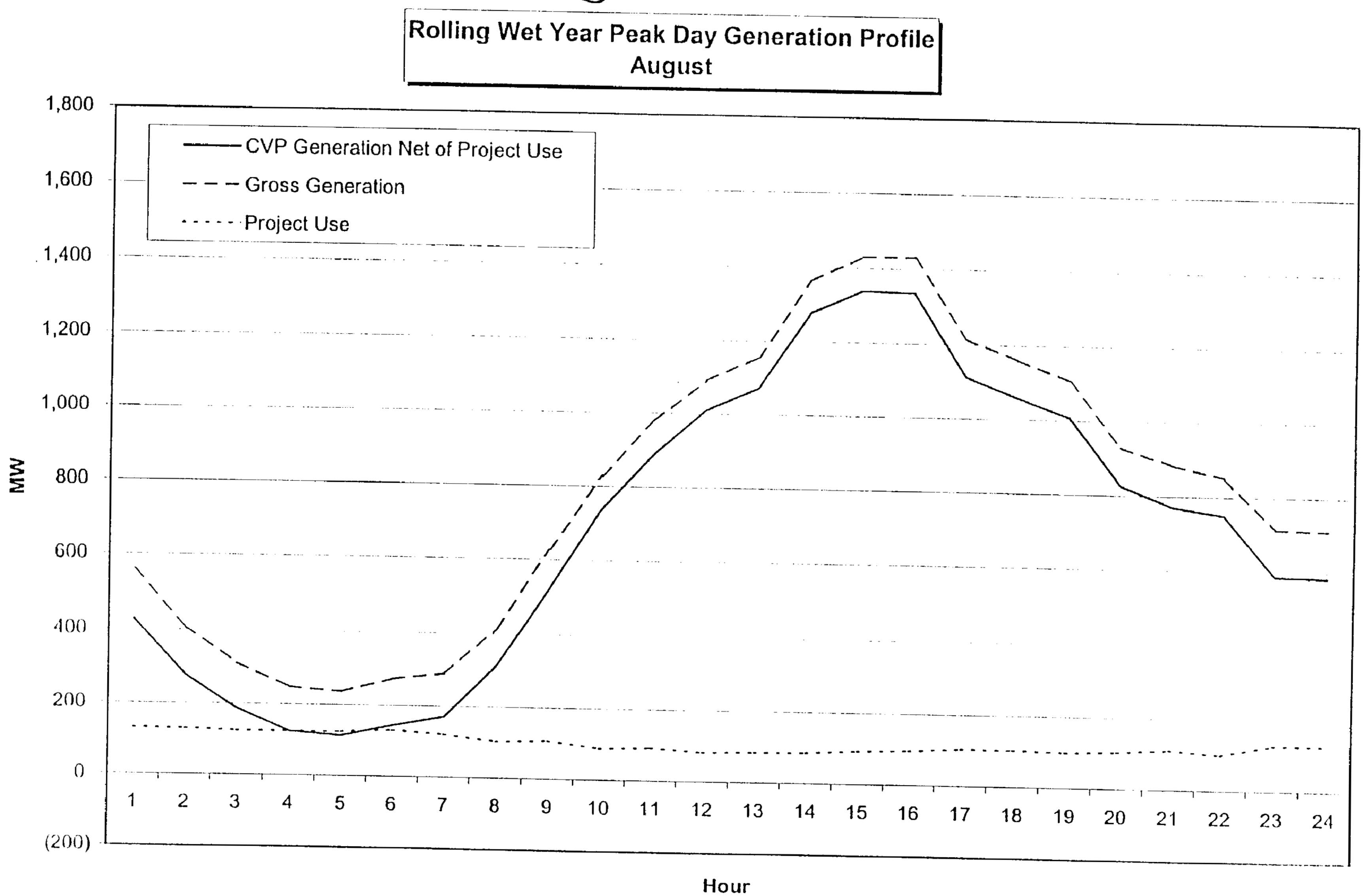

Rolling Wet Year Peak Day Generation Profile
August
CVP Generation Net of Project Use
Gross Generation
Project Use
1,800
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

Fig. 10-9

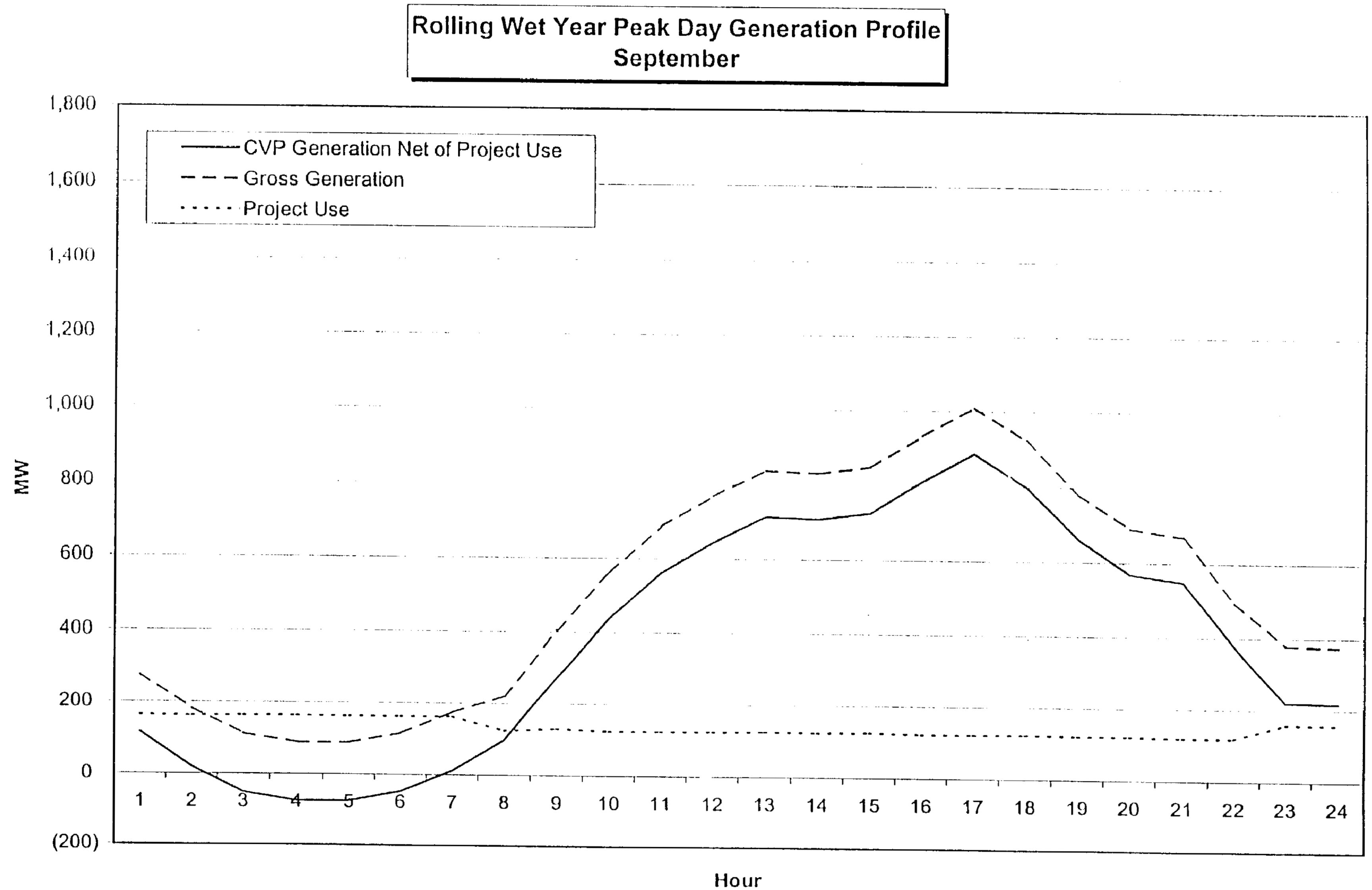

Rolling Wet Year Peak Day Generation Profile
September
CVP Generation Net of Project Use
Gross Generation
Project Use
1,800
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Hour

Fig. 10-10

Rolling Wet Year Peak Day Generation Profile
October

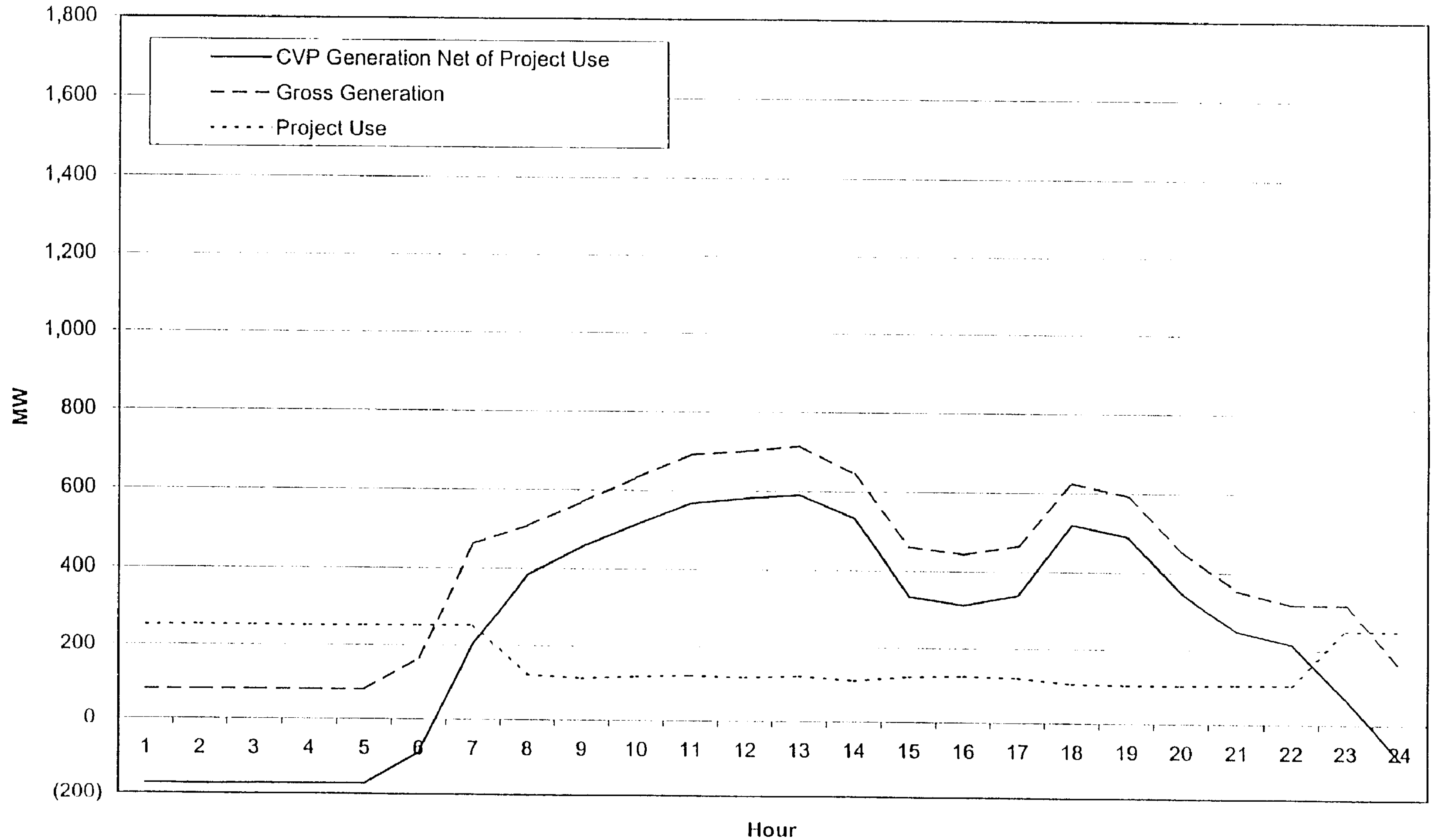
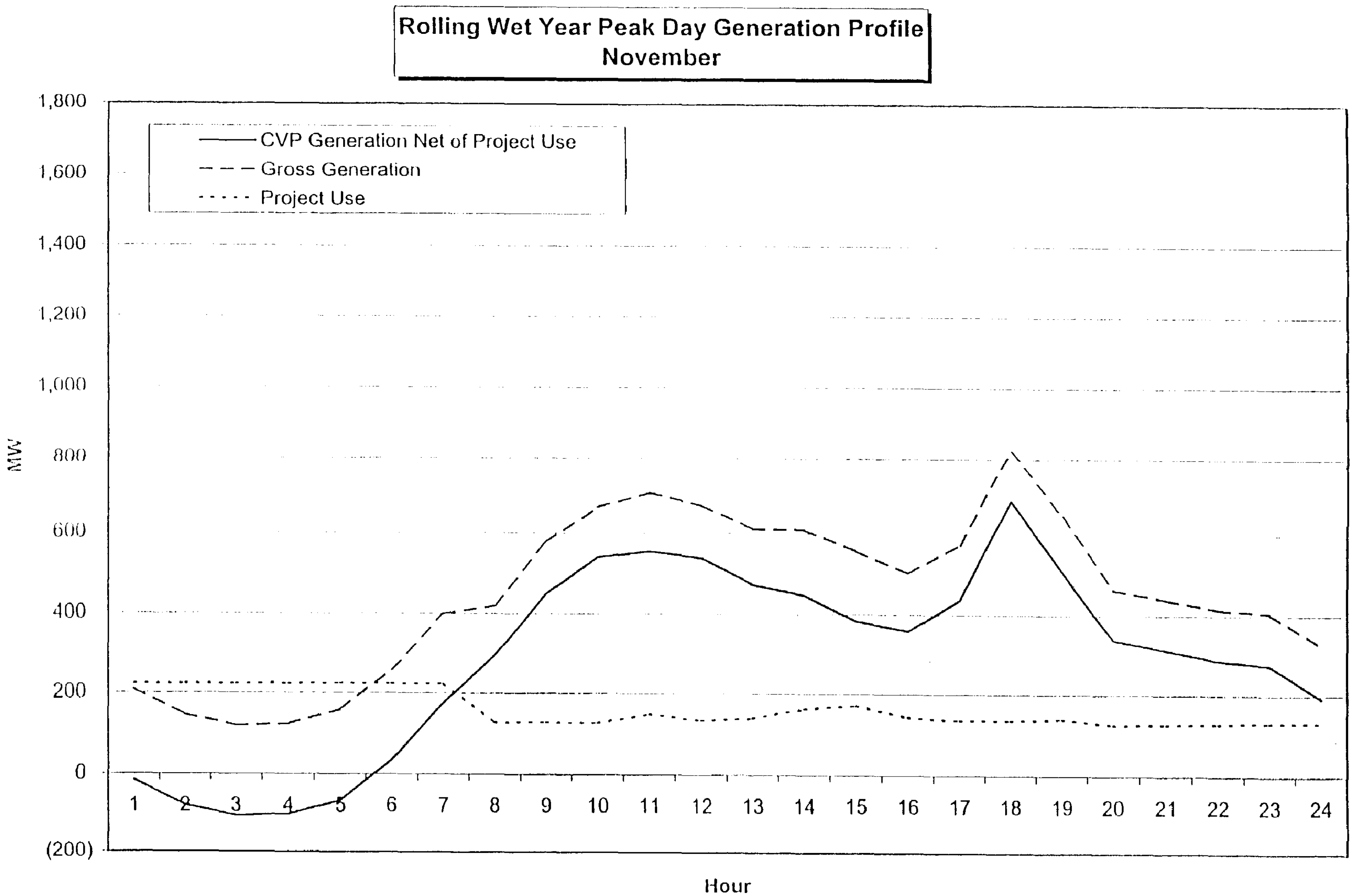
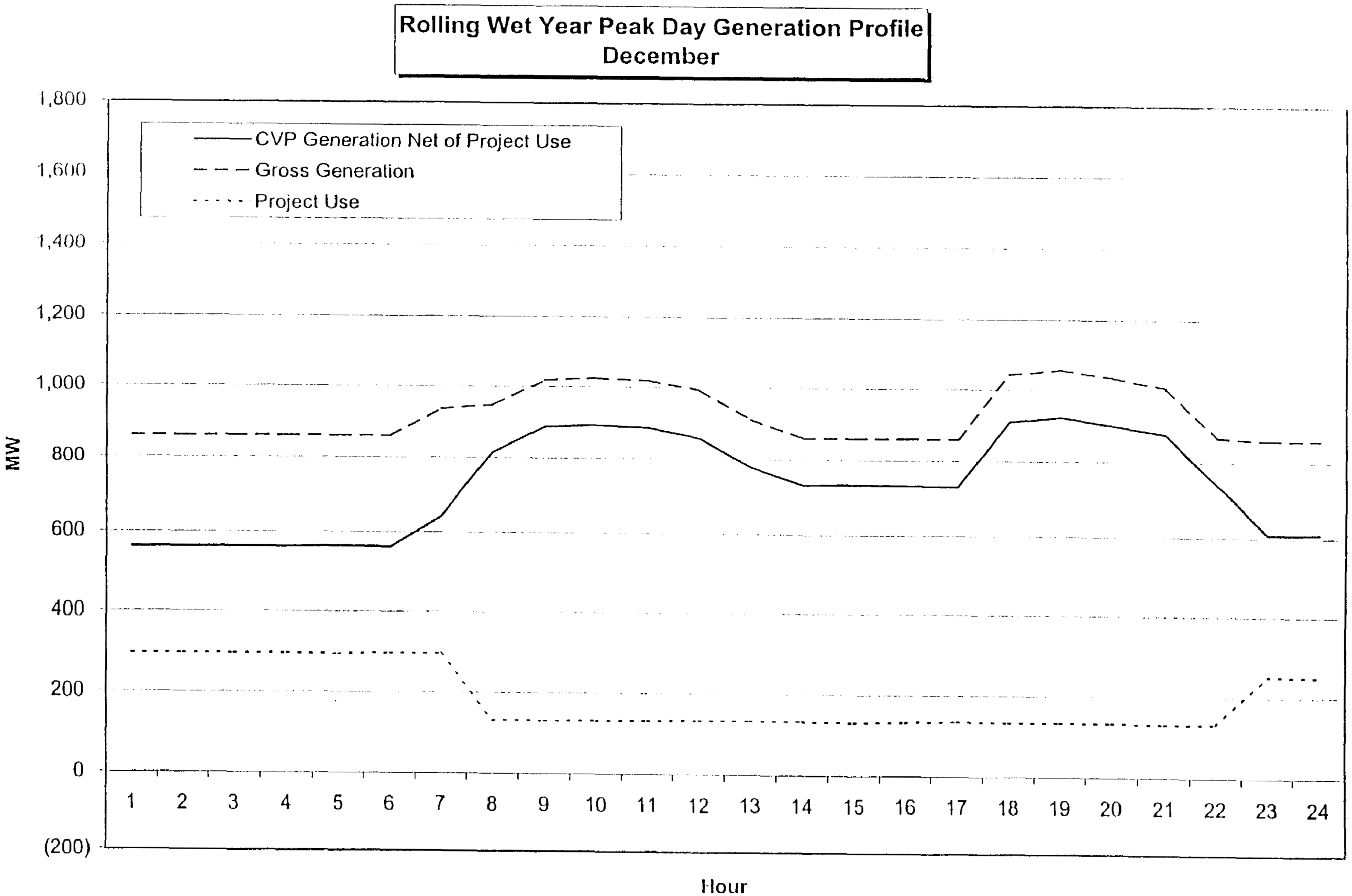


Fig. 10-11



Rolling Wet Year Peak Day Generation Profile
November
CVP Generation Net of Project Use
Gross Generation
Project Use
MW
1,800
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Hour

Fig. 10-12



Rolling Wet Year Peak Day Generation Profile
December
CVP Generation Net of Project Use
Gross Generation
Project Use
1,800
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Hour

Daily Generation Profile

Wet Year Generation

Average Weekday

Figures 11-1 thru 11-12

Fig. 11-1

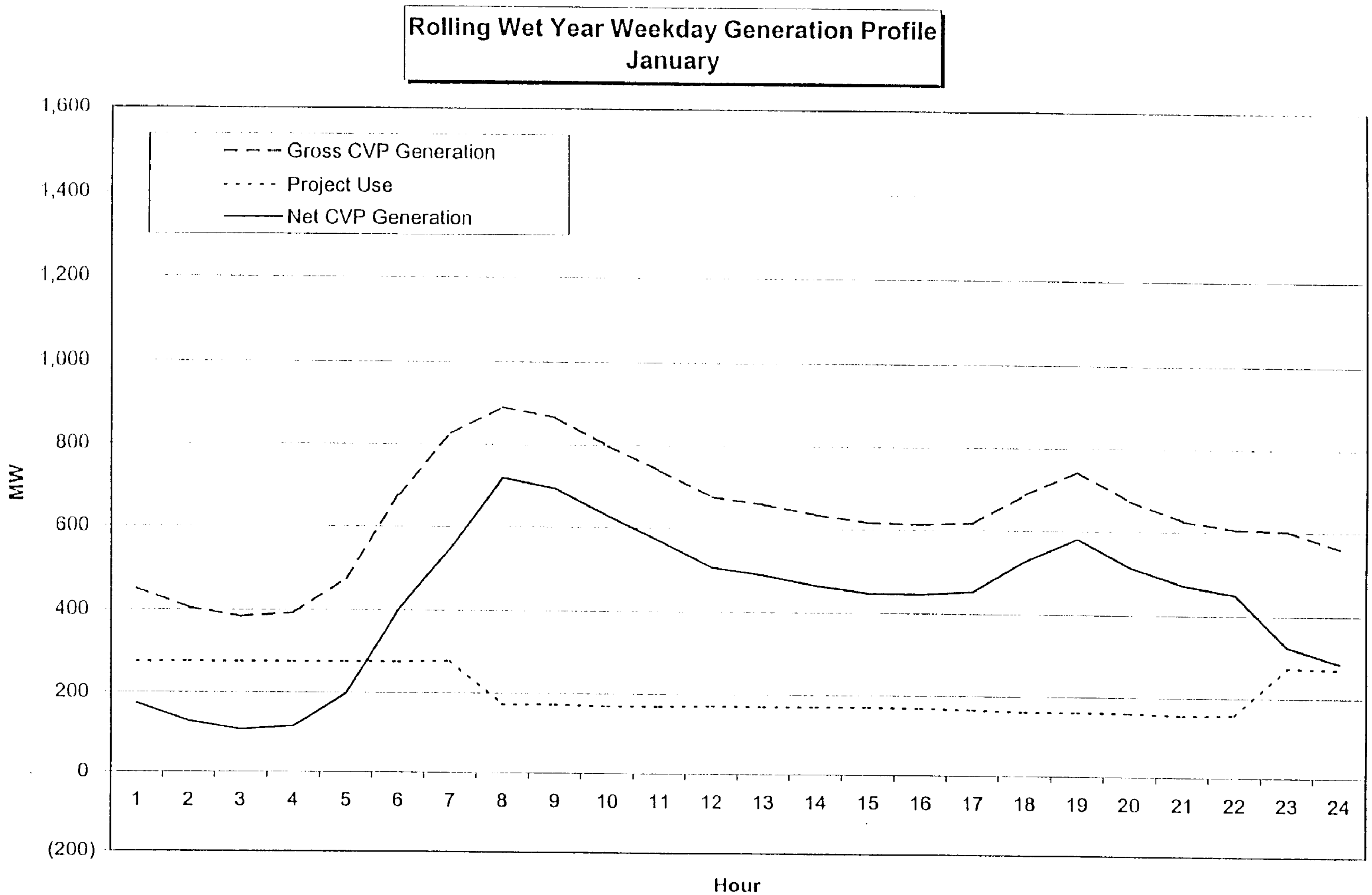
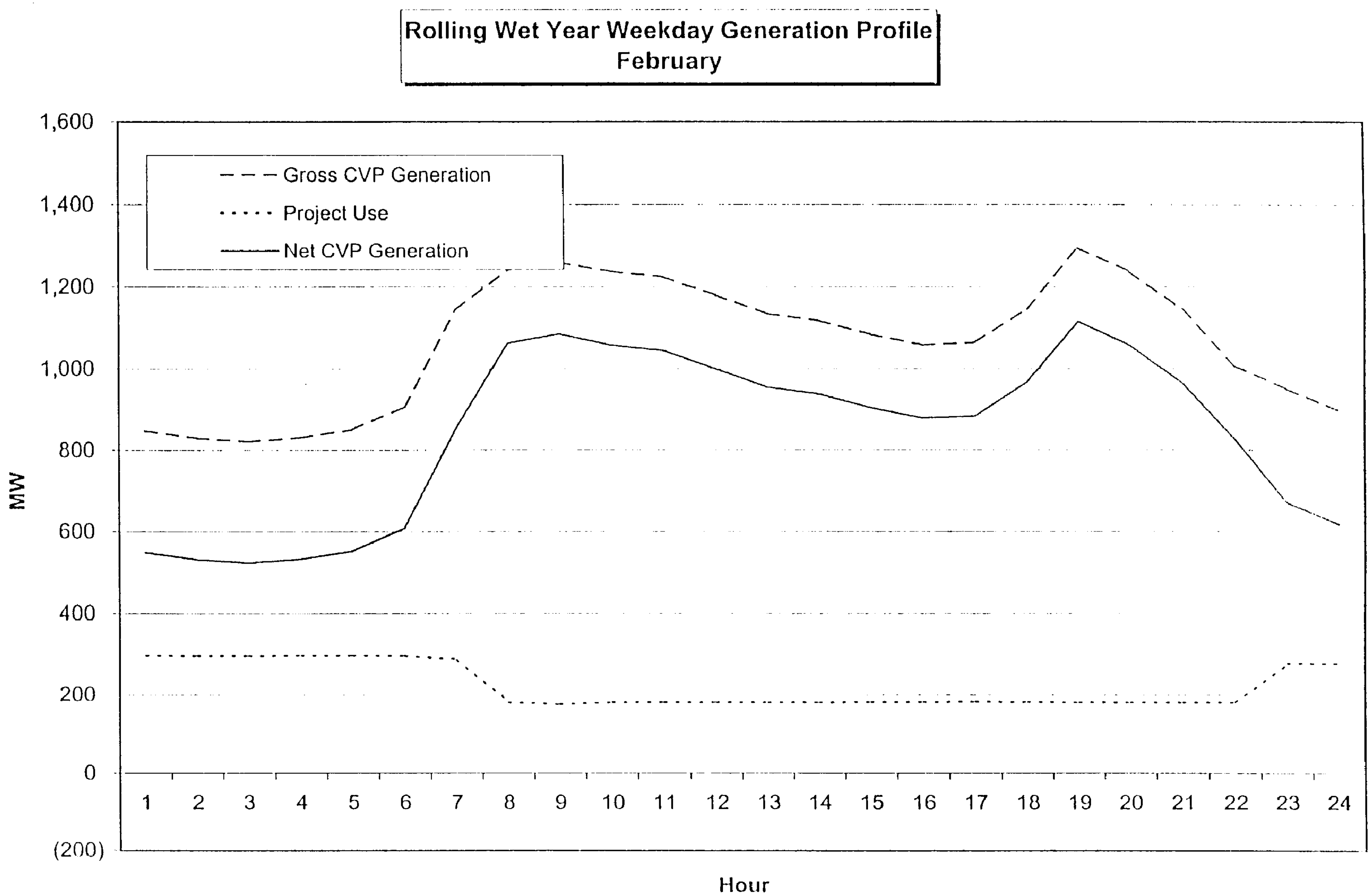

Rolling Wet Year Weekday Generation Profile
January
Gross CVP Generation
Project Use
Net CVP Generation
MW
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Hour

Fig. 11-2



Rolling Wet Year Weekday Generation Profile
February
Gross CVP Generation
Project Use
Net CVP Generation
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Hour

Fig. 11-3

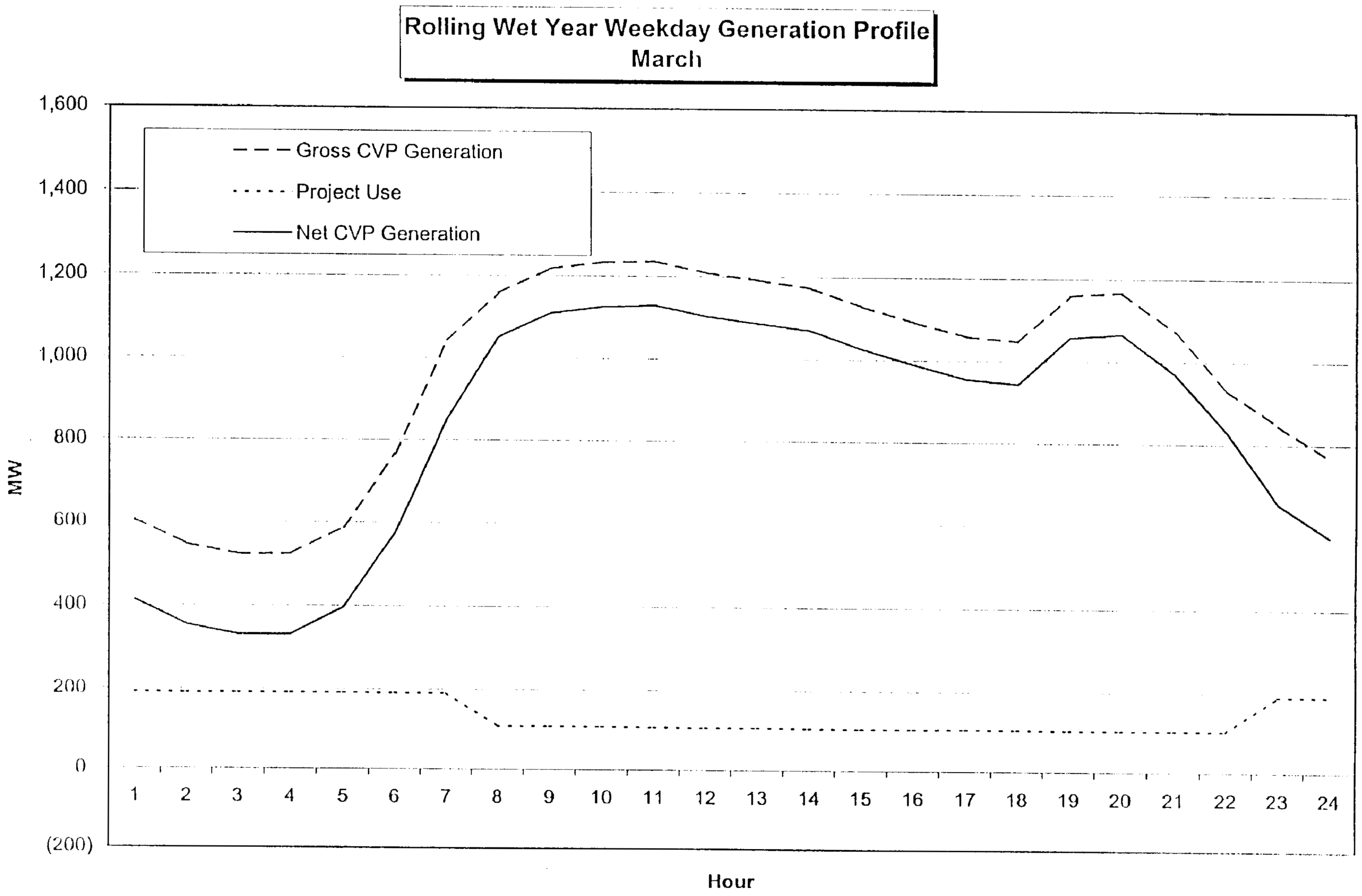

Rolling Wet Year Weekday Generation Profile
March
Gross CVP Generation
Project Use
Net CVP Generation
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Hour

Fig. 11-4

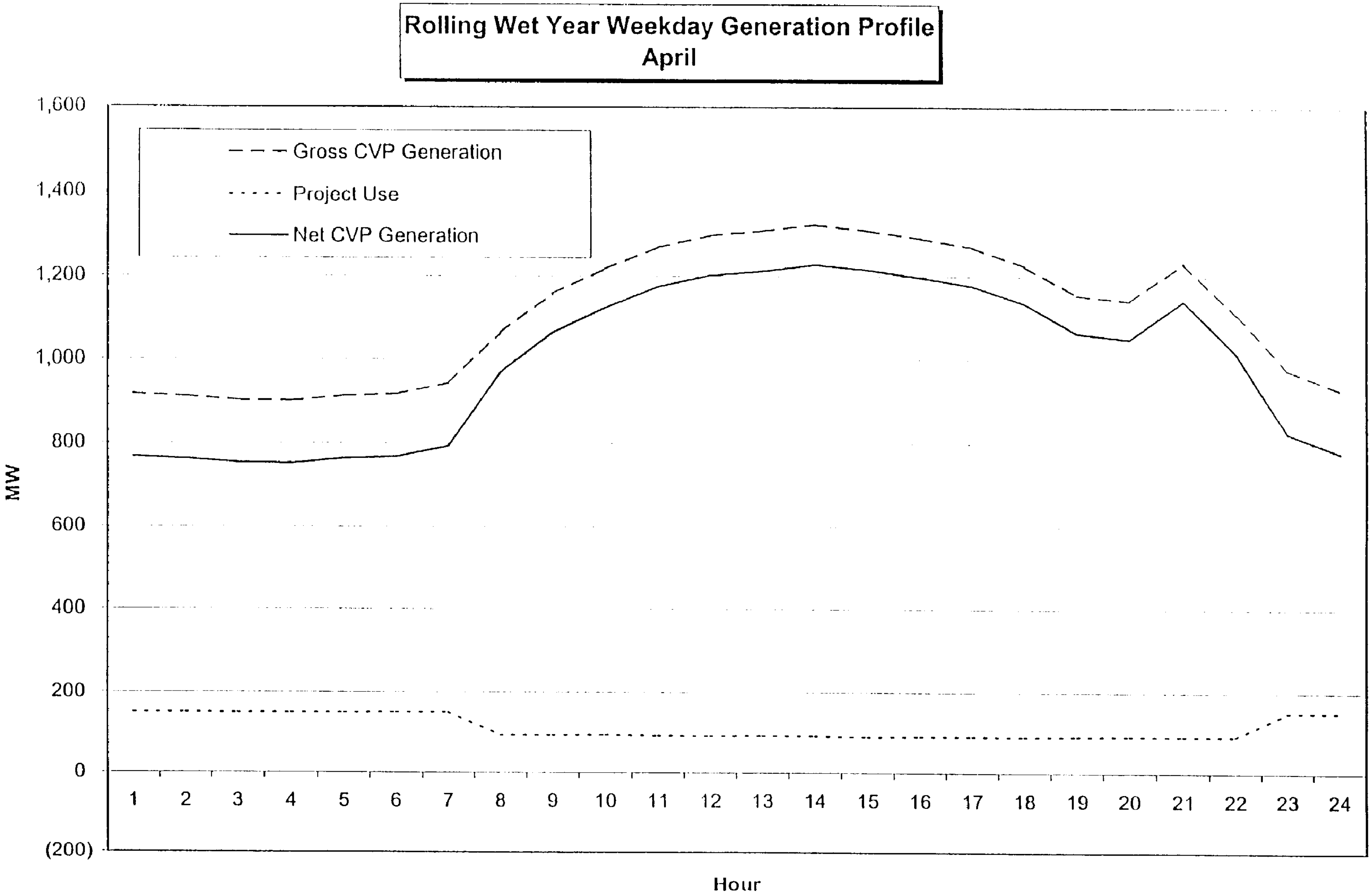

Rolling Wet Year Weekday Generation Profile
April
Gross CVP Generation
Project Use
Net CVP Generation
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Hour

Fig. 11-5

Rolling Wet Year Weekday Generation Profile
May

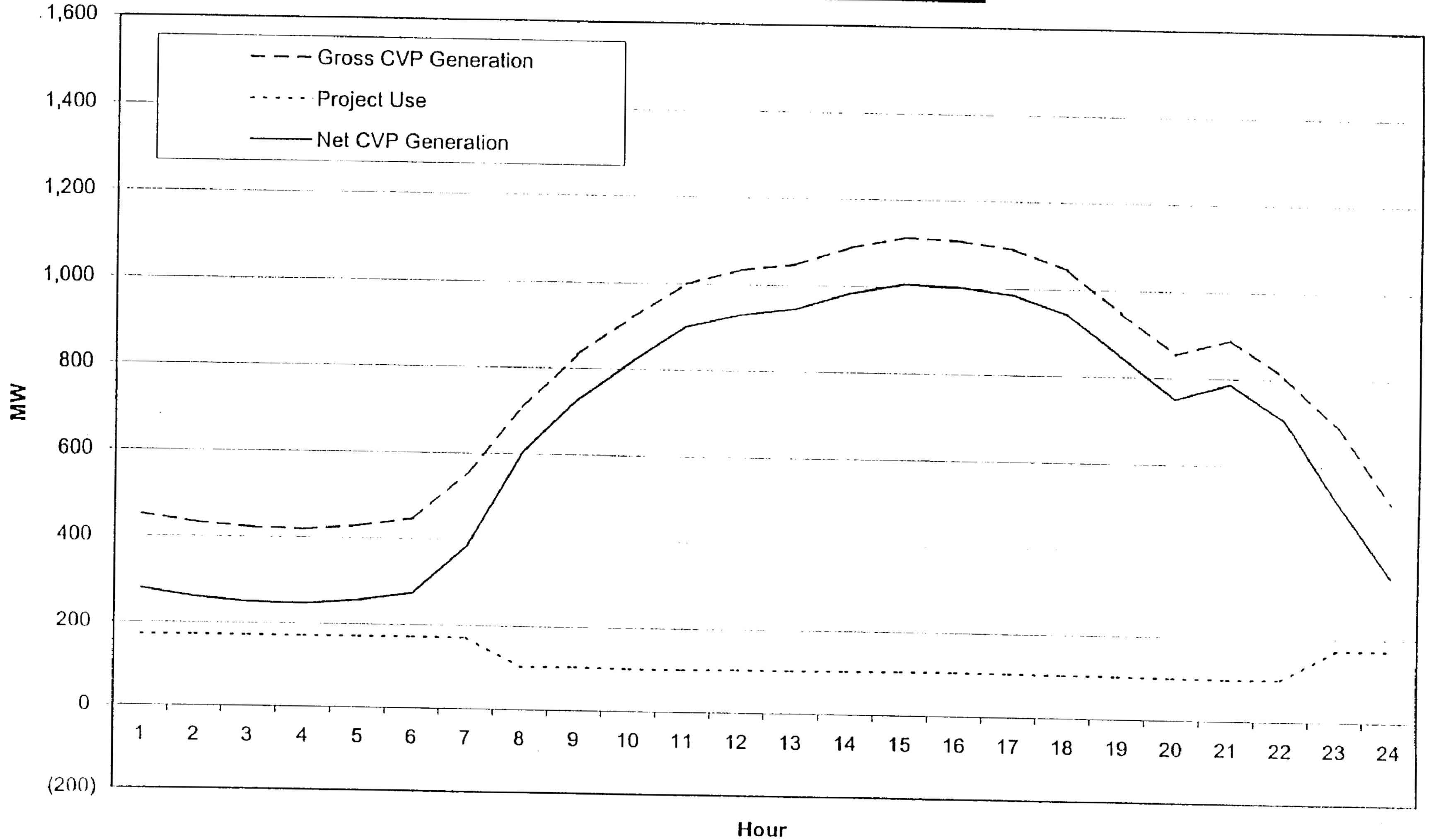
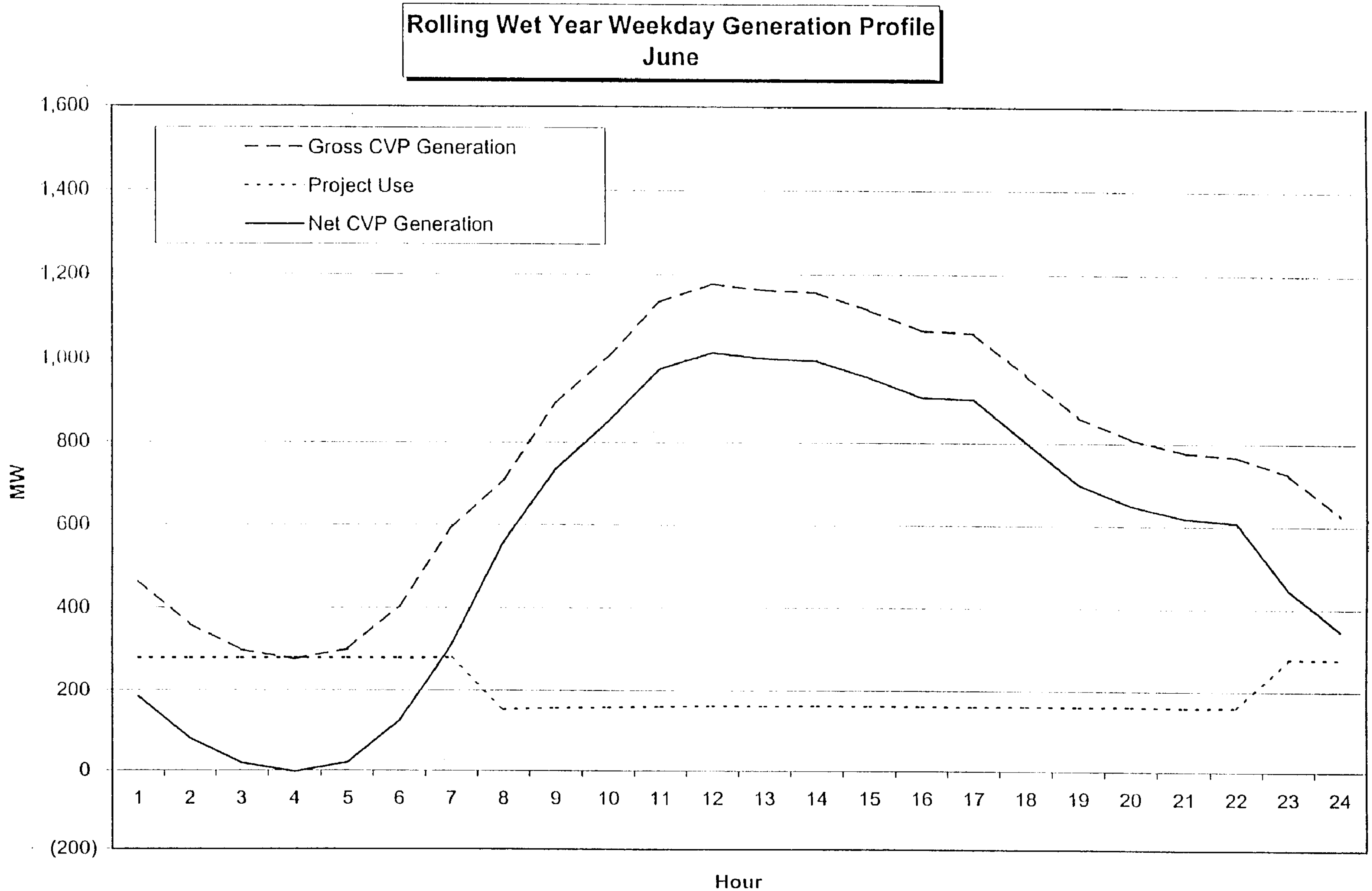


Fig. 11-6



Rolling Wet Year Weekday Generation Profile
June
Gross CVP Generation
Project Use
Net CVP Generation
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Hour

Fig. 11-7

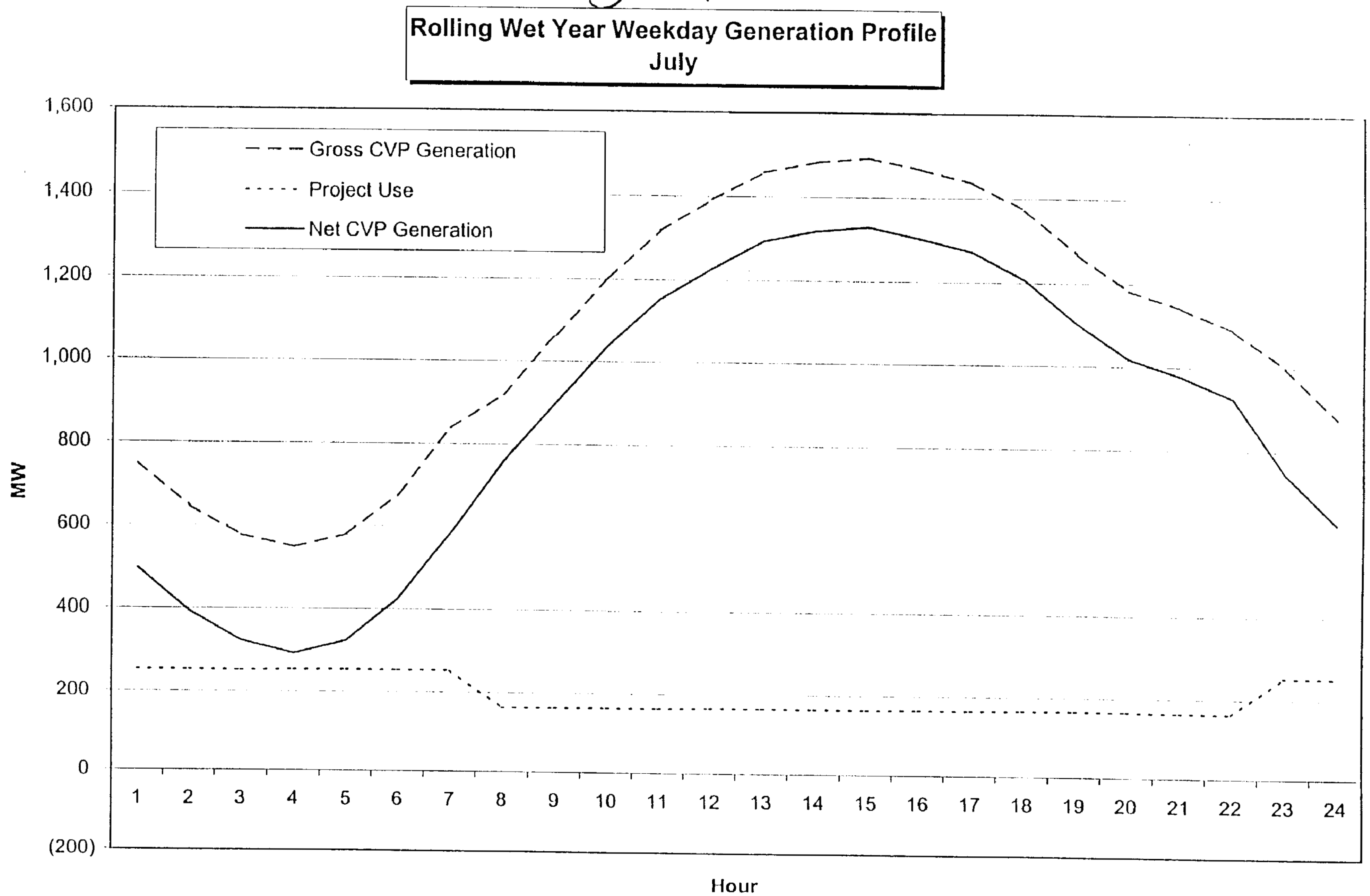

Rolling Wet Year Weekday Generation Profile
July
Gross CVP Generation
Project Use
Net CVP Generation
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

Fig 11-8

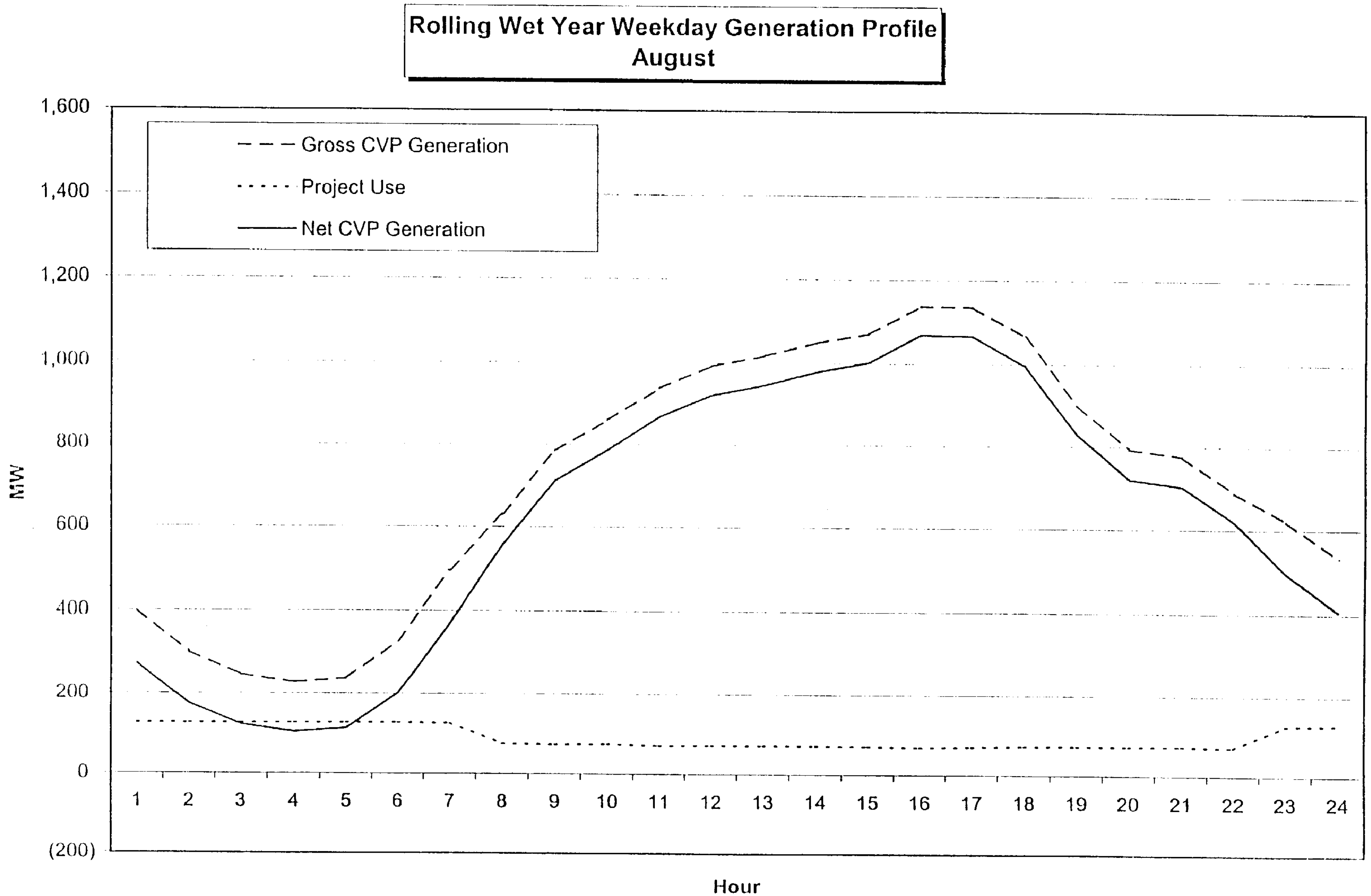

Rolling Wet Year Weekday Generation Profile
August
Gross CVP Generation
Project Use
Net CVP Generation
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Hour

Fig. 11-9

**Rolling Wet Year Weekday Generation Profile
September**

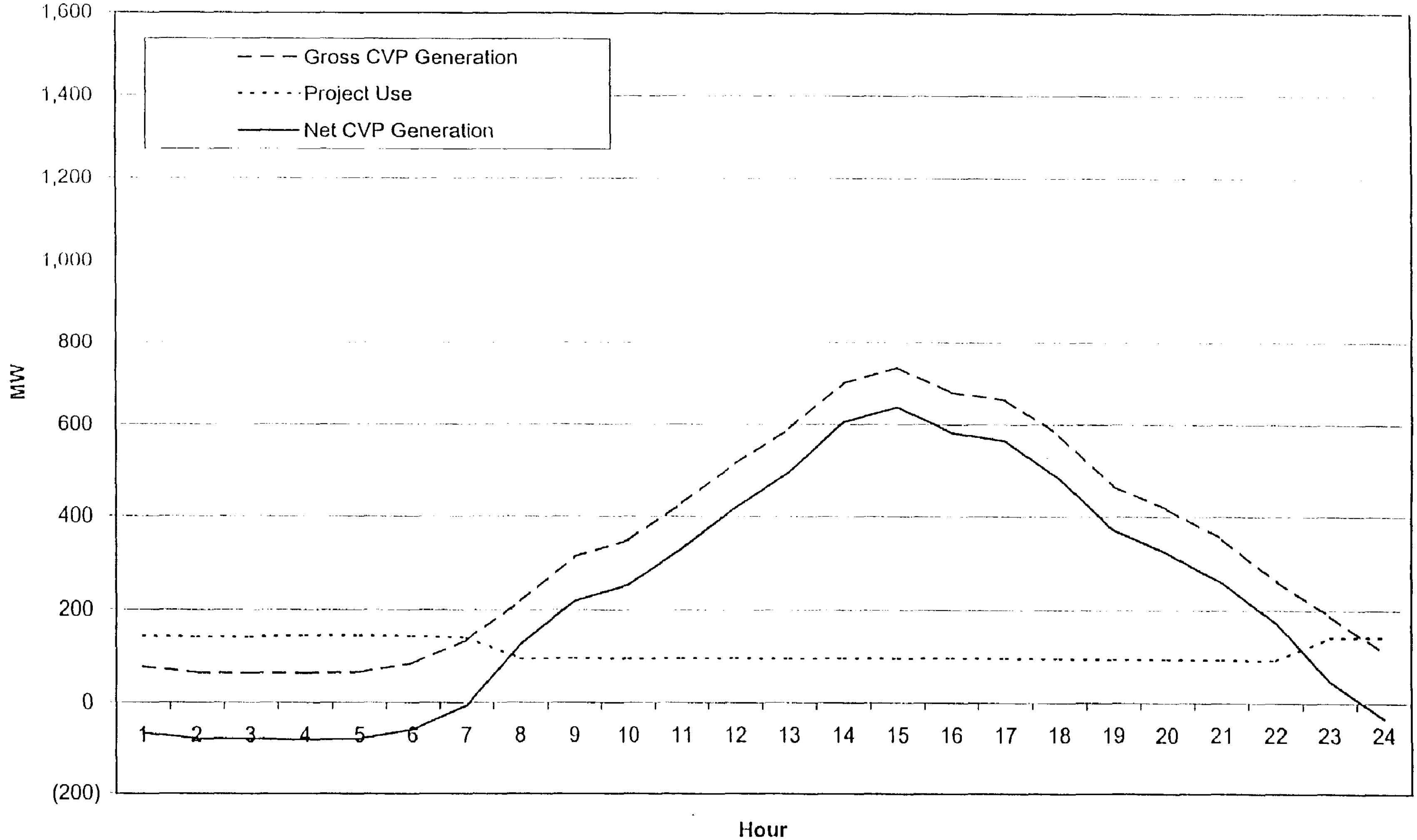


Fig. 11-10

Rolling Wet Year Weekday Generation Profile
October

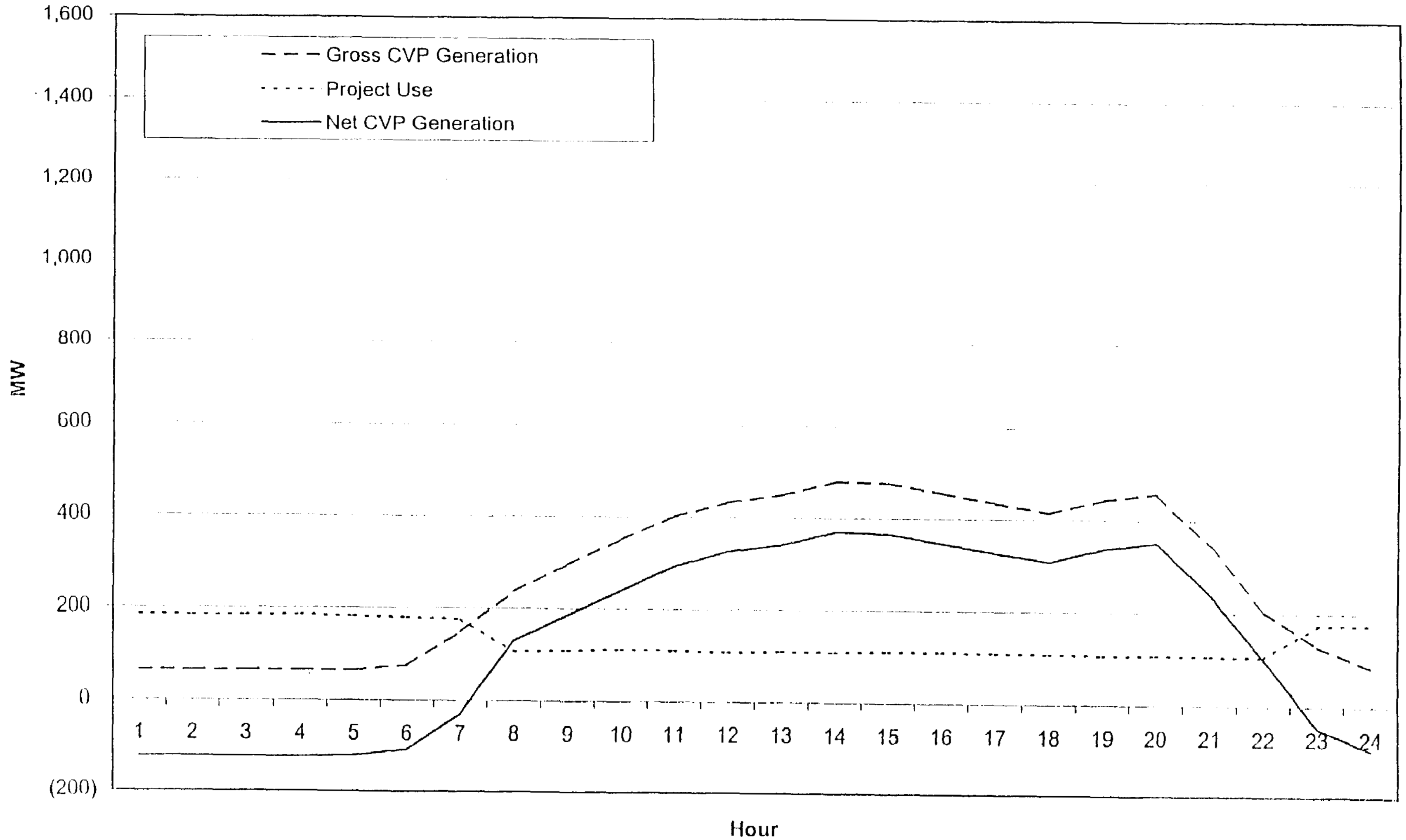
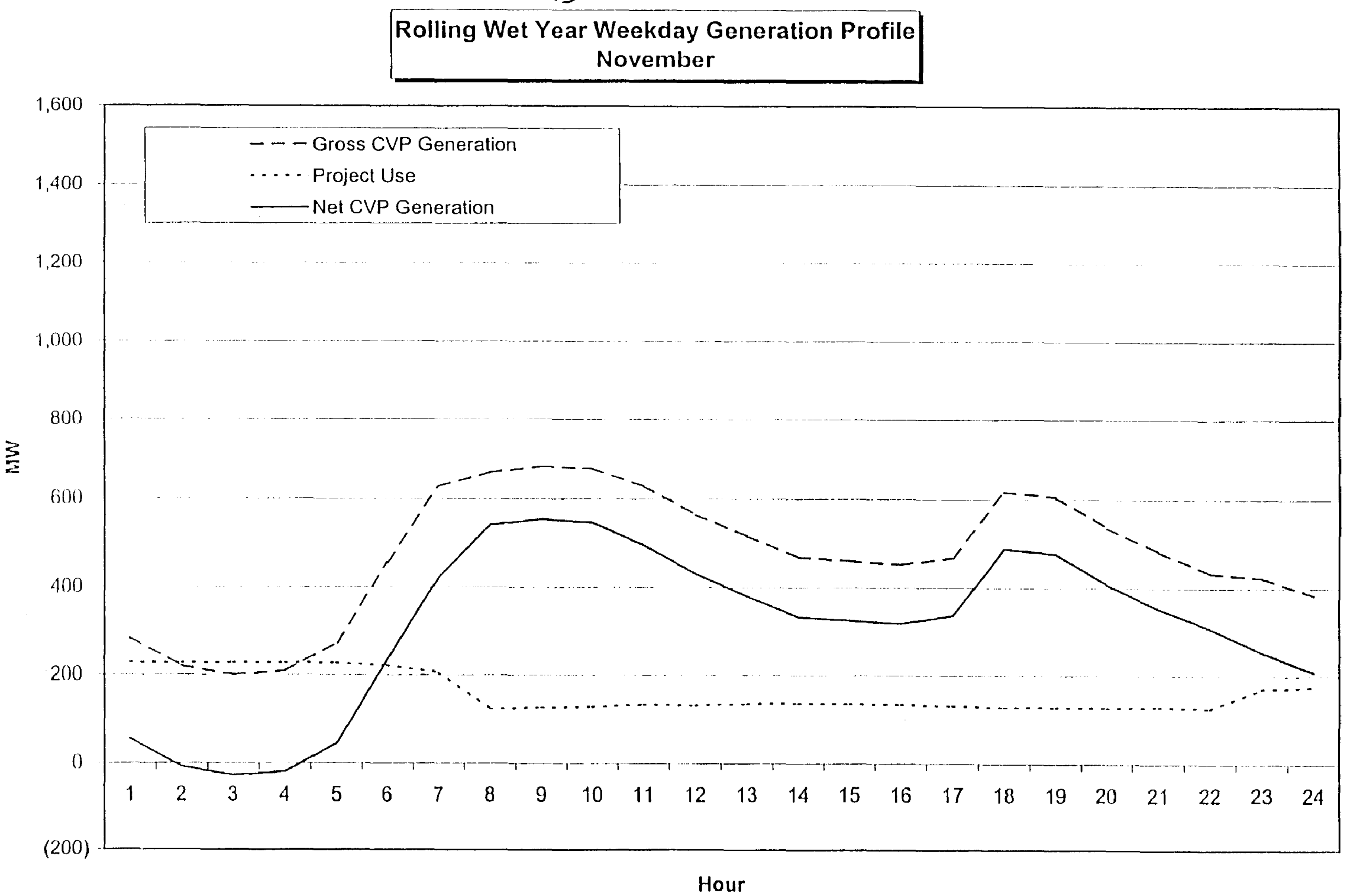


Fig. 11-11


Rolling Wet Year Weekday Generation Profile
November
Gross CVP Generation
Project Use
Net CVP Generation
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1
2
3
4
5
6
7
8
9
10
11
12
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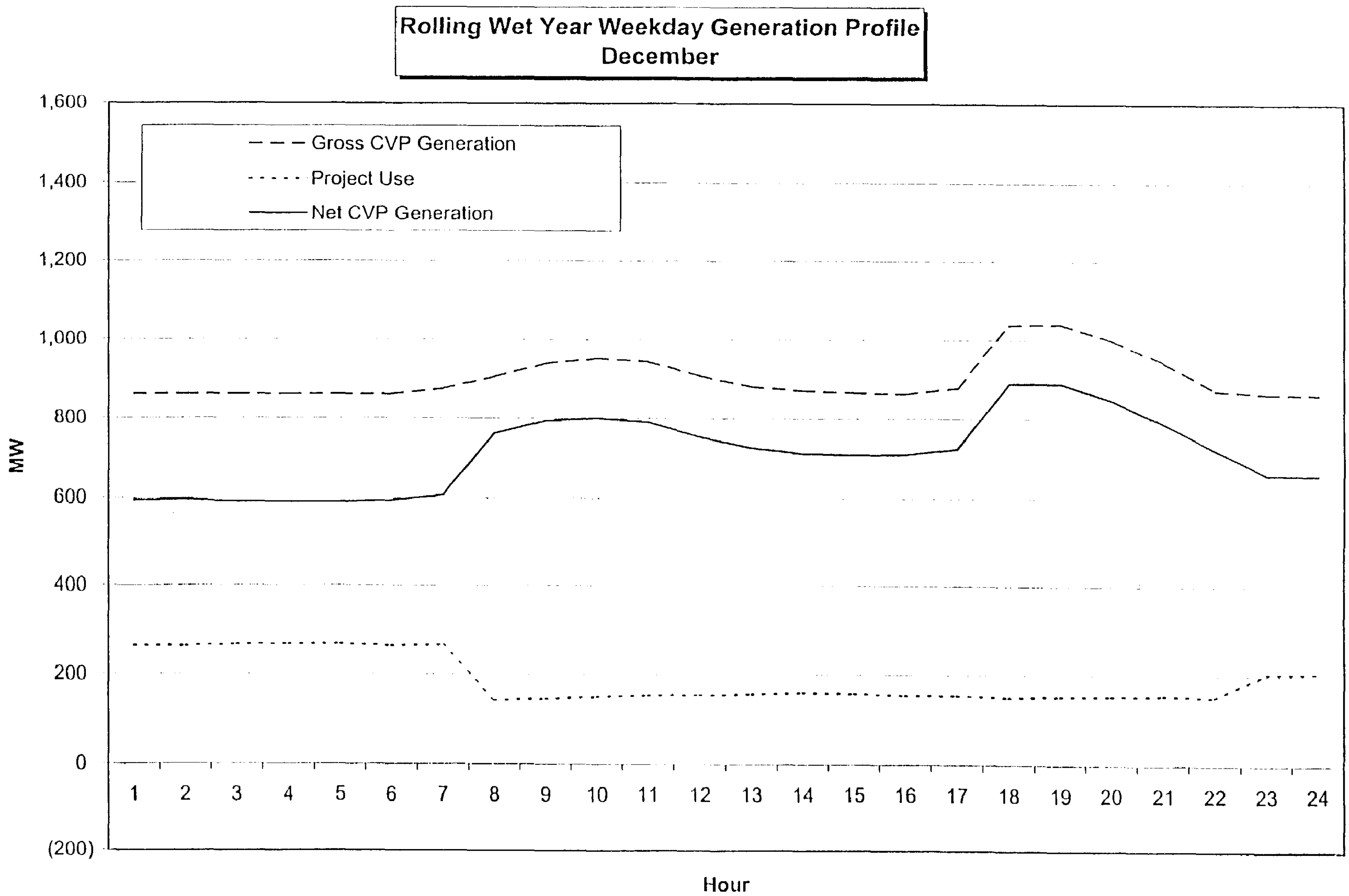
14
15
16
17
18
19
20
21
22
23
24
Hour

Fig. 11-12



Rolling Wet Year Weekday Generation Profile
December
Gross CVP Generation
Project Use
Net CVP Generation
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1
2
3
4
5
6
7
8
9
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11
12
13
14
15
16
17
18
19
20
21
22
23
24
Hour

Daily Generation Profile

Wet Year Generation

Average Weekend

Figures 12-1 thru 12-12

Fig. 12-1

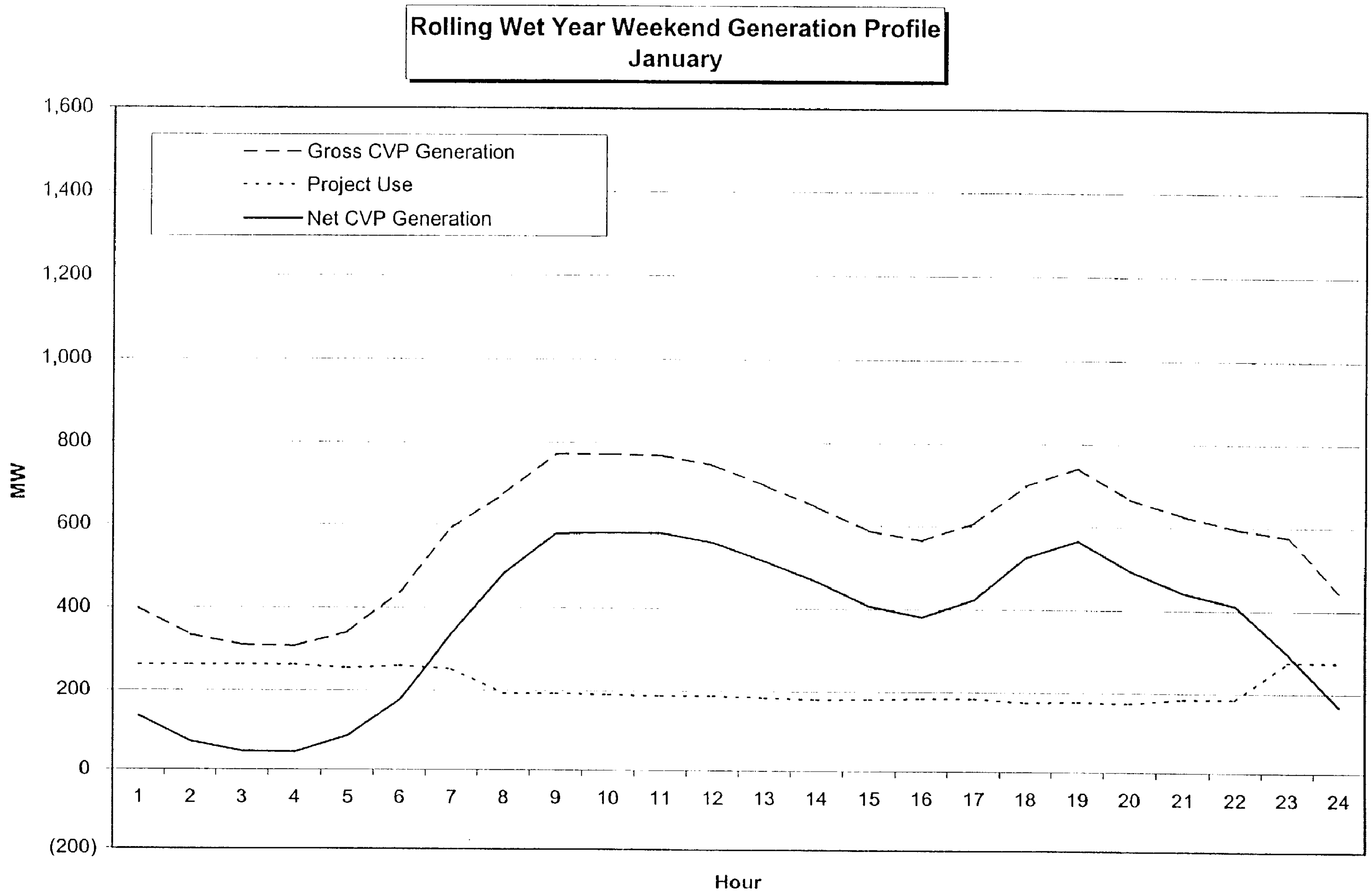

Rolling Wet Year Weekend Generation Profile
January
Gross CVP Generation
Project Use
Net CVP Generation
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

Fig. 12-2

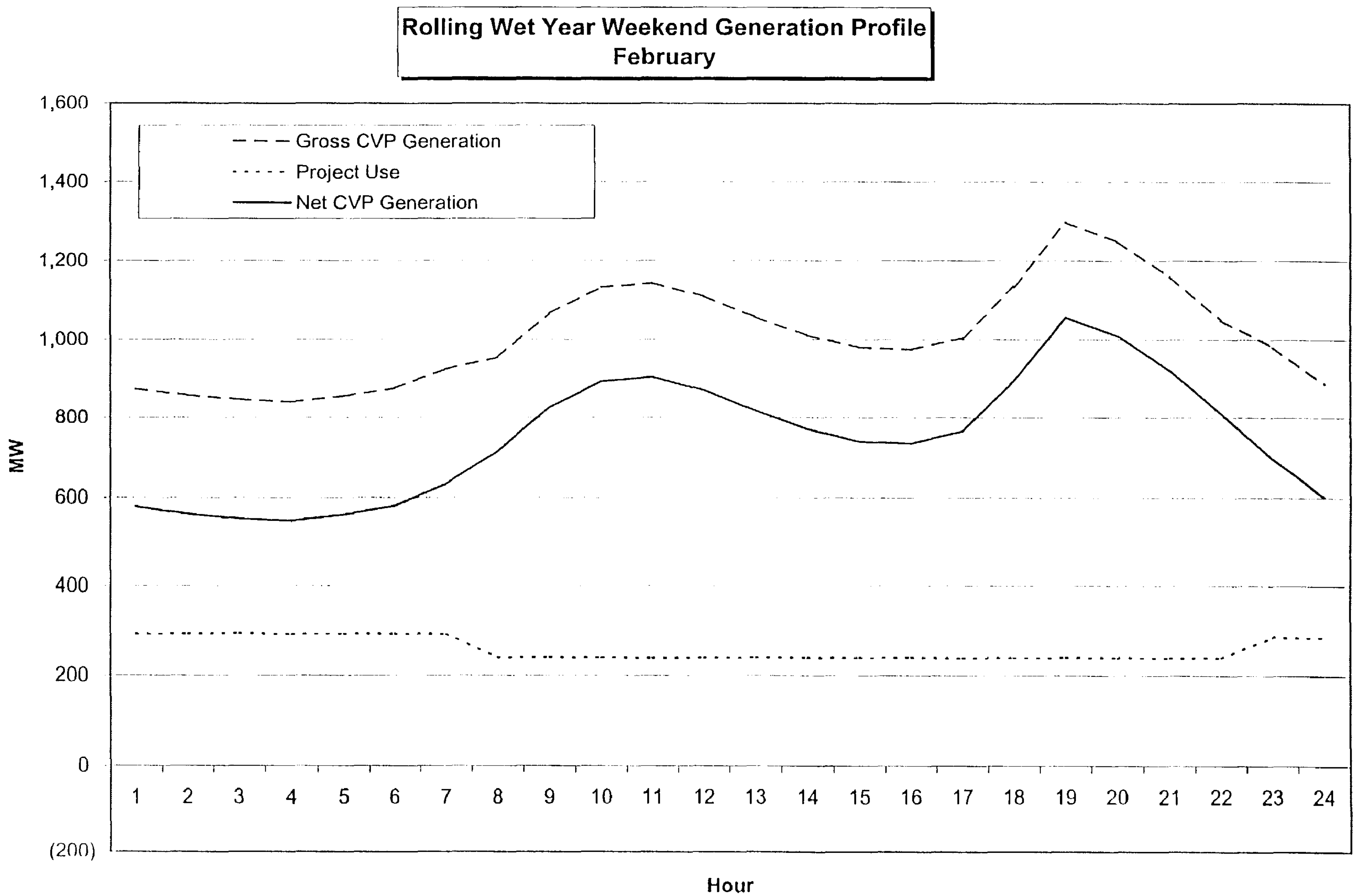
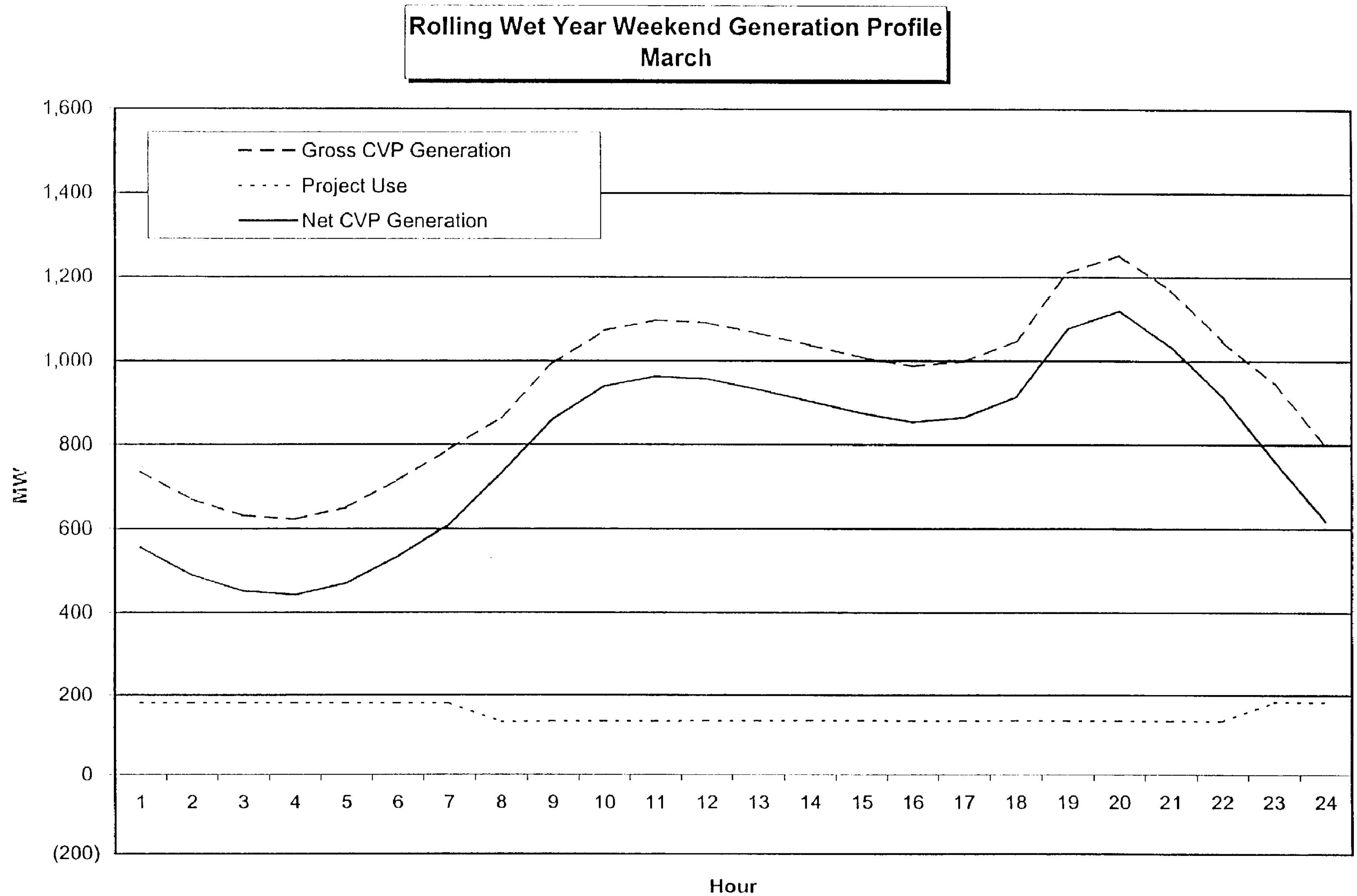

Rolling Wet Year Weekend Generation Profile
February
Gross CVP Generation
Project Use
Net CVP Generation
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

Fig. 12-3



Rolling Wet Year Weekend Generation Profile
March
Gross CVP Generation
Project Use
Net CVP Generation
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

Fig. 12-4

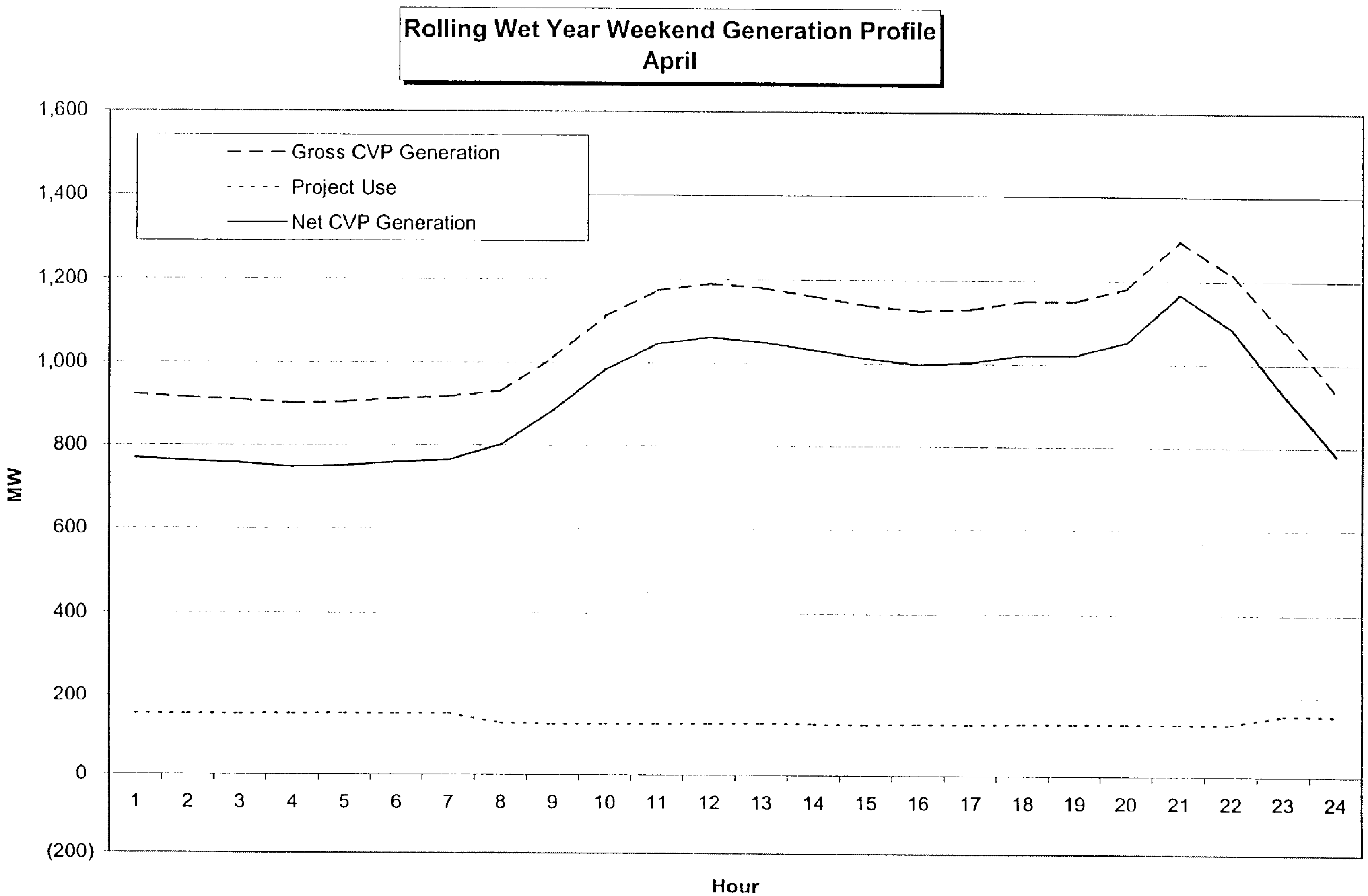
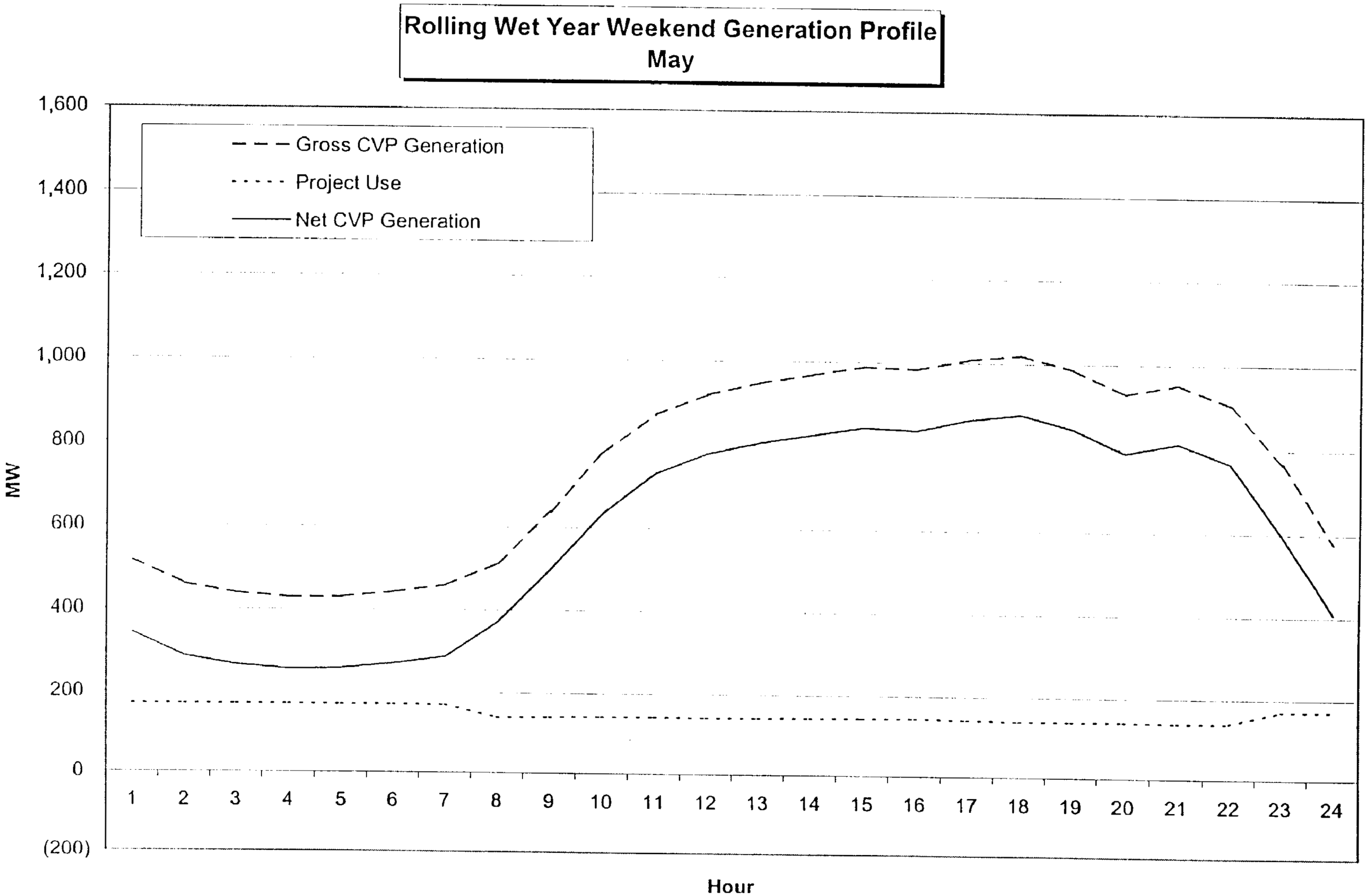

Rolling Wet Year Weekend Generation Profile
April
Gross CVP Generation
Project Use
Net CVP Generation
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

Fig. 12-5


Rolling Wet Year Weekend Generation Profile
May
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
Gross CVP Generation
Project Use
Net CVP Generation
1
2
3
4
5
6
7
8
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11
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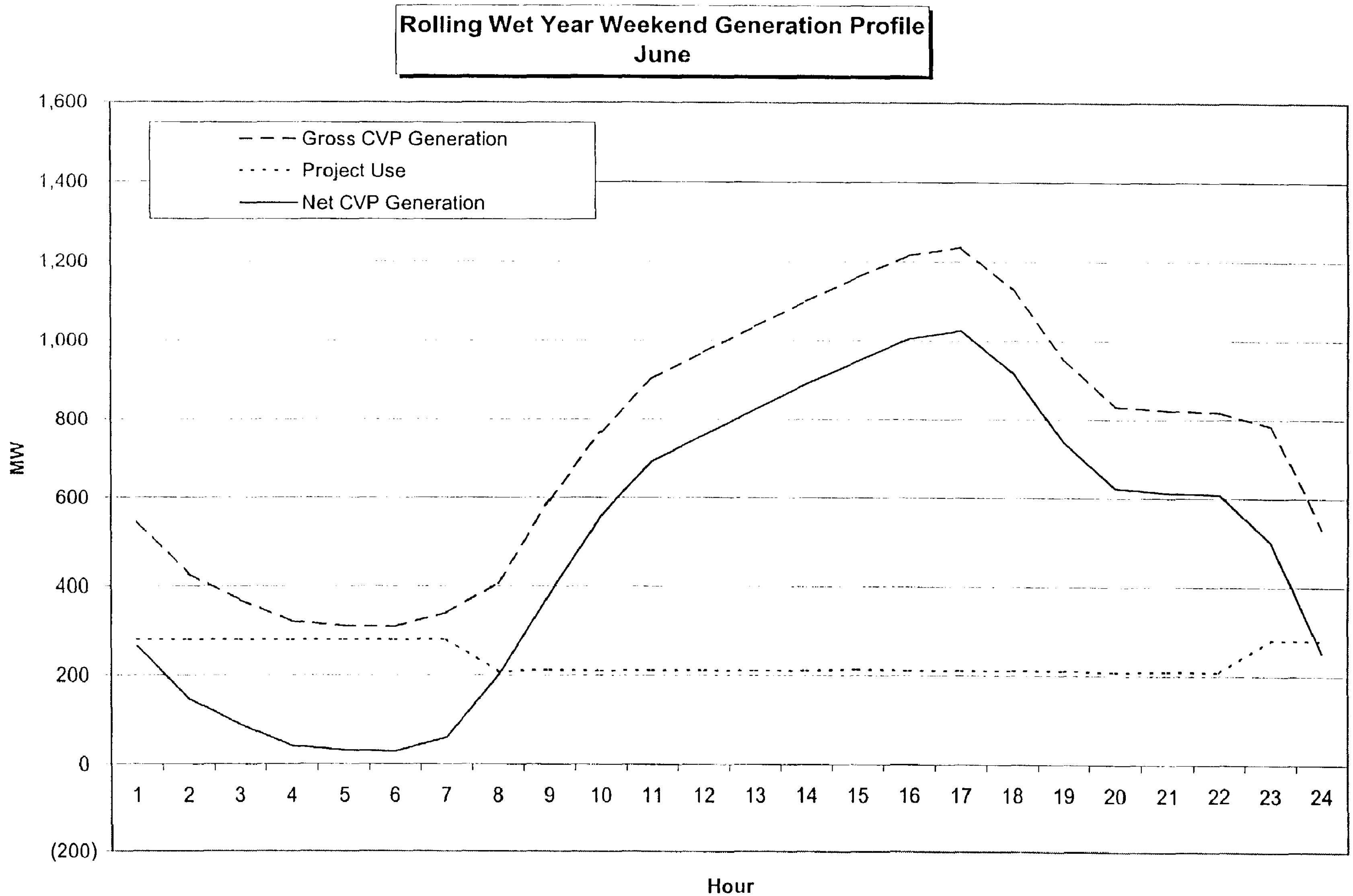
14
15
16
17
18
19
20
21
22
23
24
Hour

Fig. 12-6



Rolling Wet Year Weekend Generation Profile
June
Gross CVP Generation
Project Use
Net CVP Generation
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1
2
3
4
5
6
7
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16
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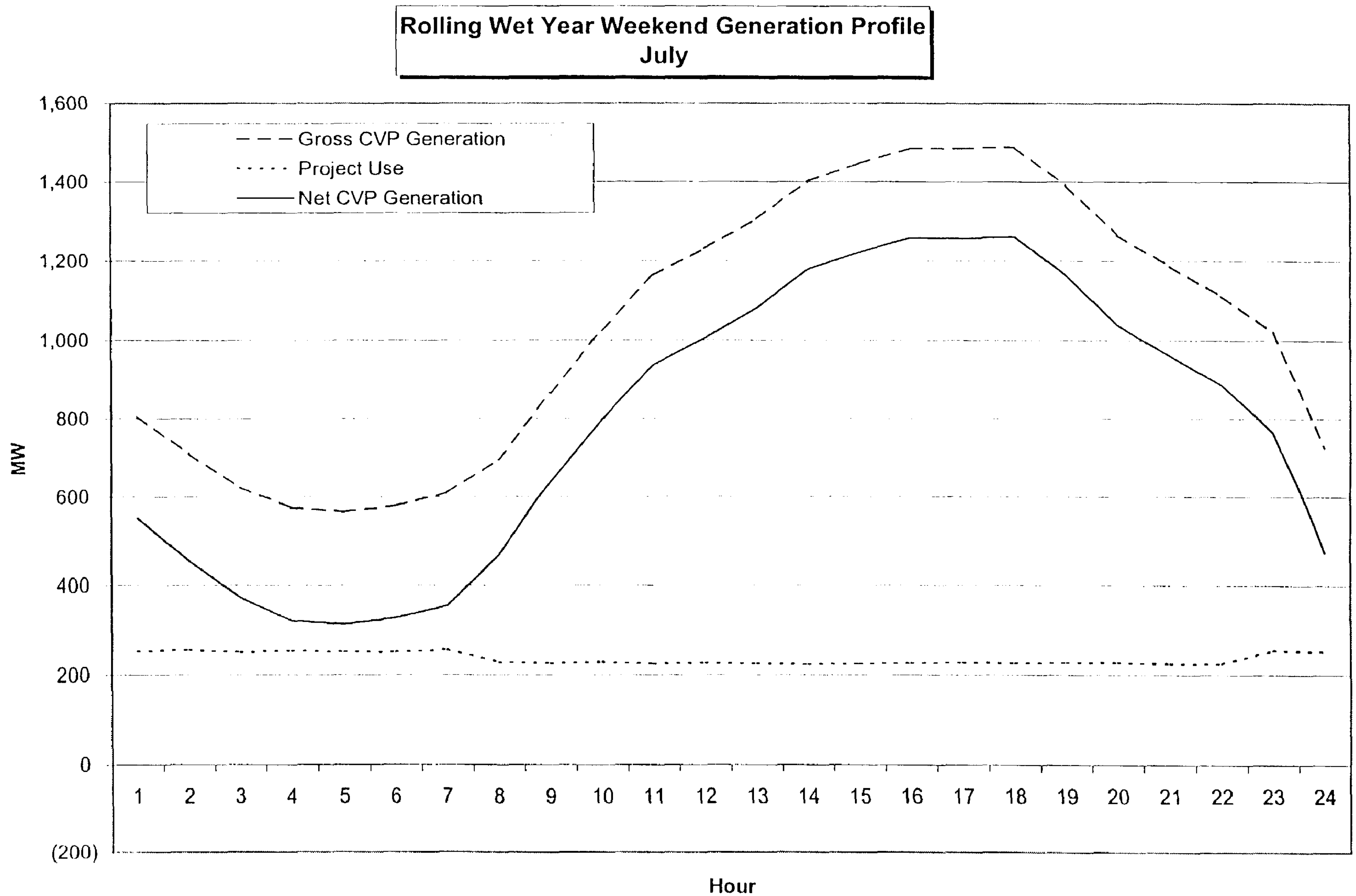
18
19
20
21
22
23
24
Hour

Fig. 12-7


Rolling Wet Year Weekend Generation Profile
July
Gross CVP Generation
Project Use
Net CVP Generation
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1
2
3
4
5
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18
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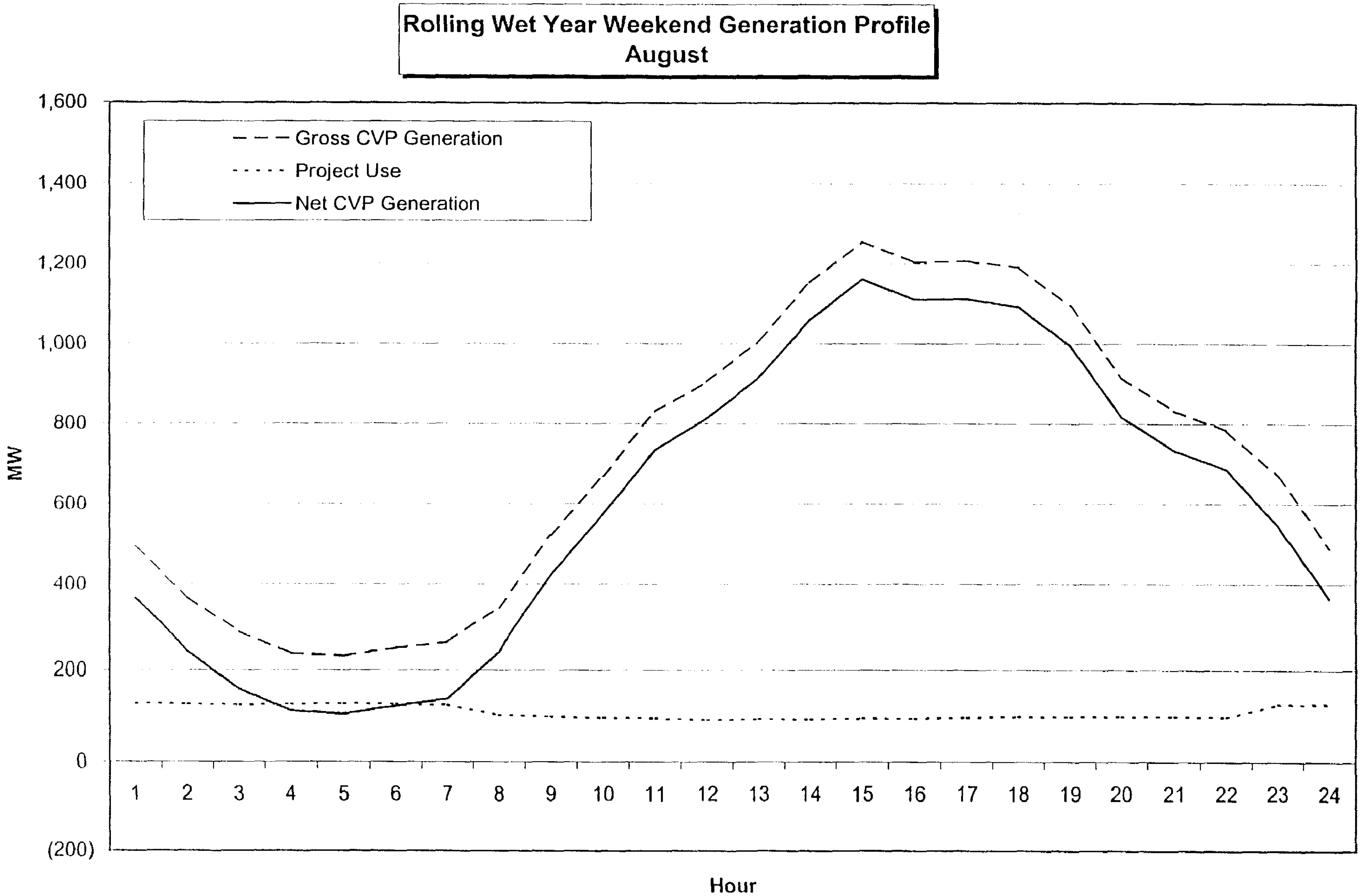
20
21
22
23
24
Hour

Fig. 12-8


Rolling Wet Year Weekend Generation Profile
August
Gross CVP Generation
Project Use
Net CVP Generation
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1
2
3
4
5
6
7
8
9
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11
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16
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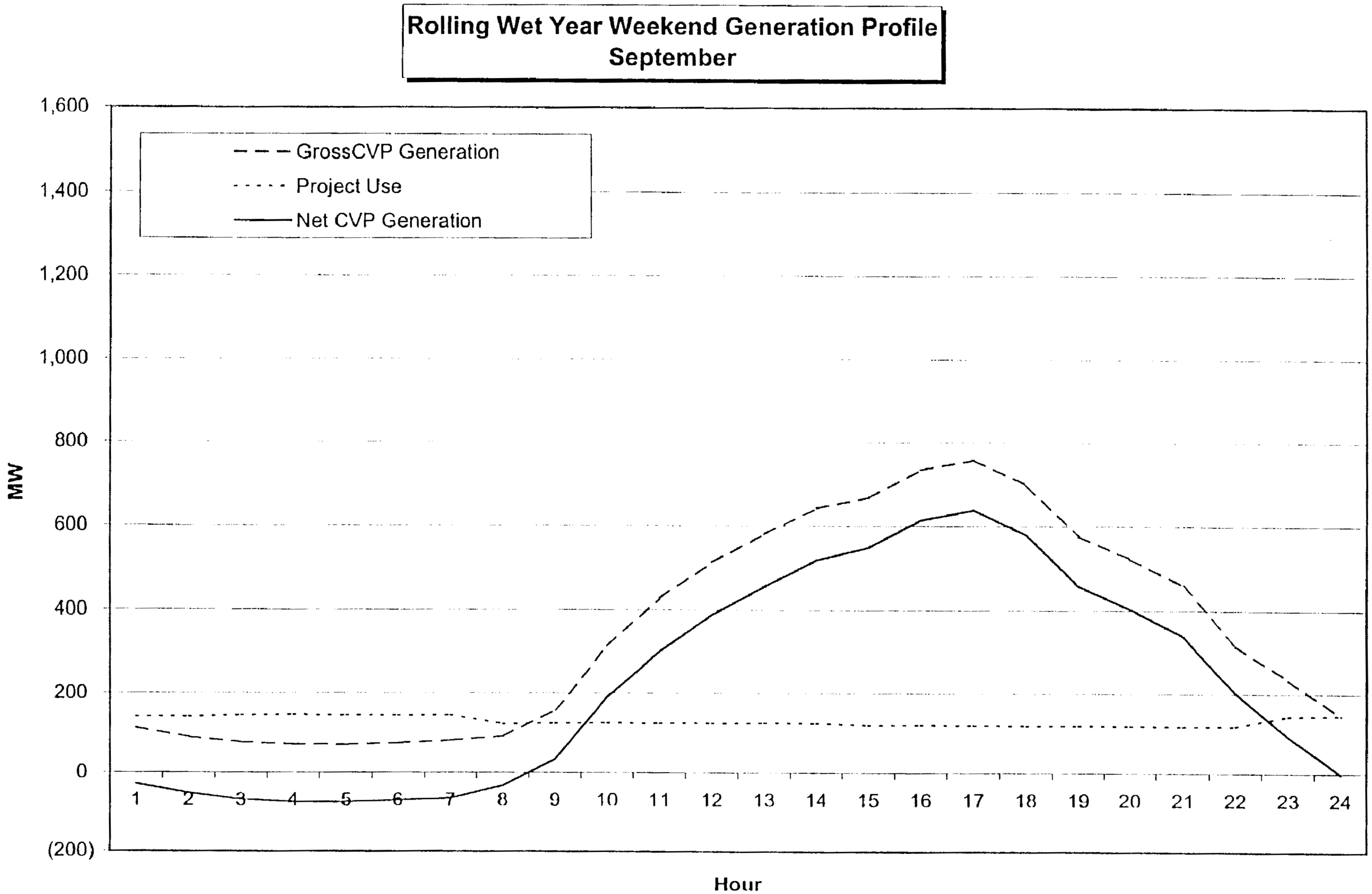
18
19
20
21
22
23
24
Hour

Fig. 12-9



Rolling Wet Year Weekend Generation Profile
September
GrossCVP Generation
Project Use
Net CVP Generation
MW
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
1
2
3
4
5
6
7
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16
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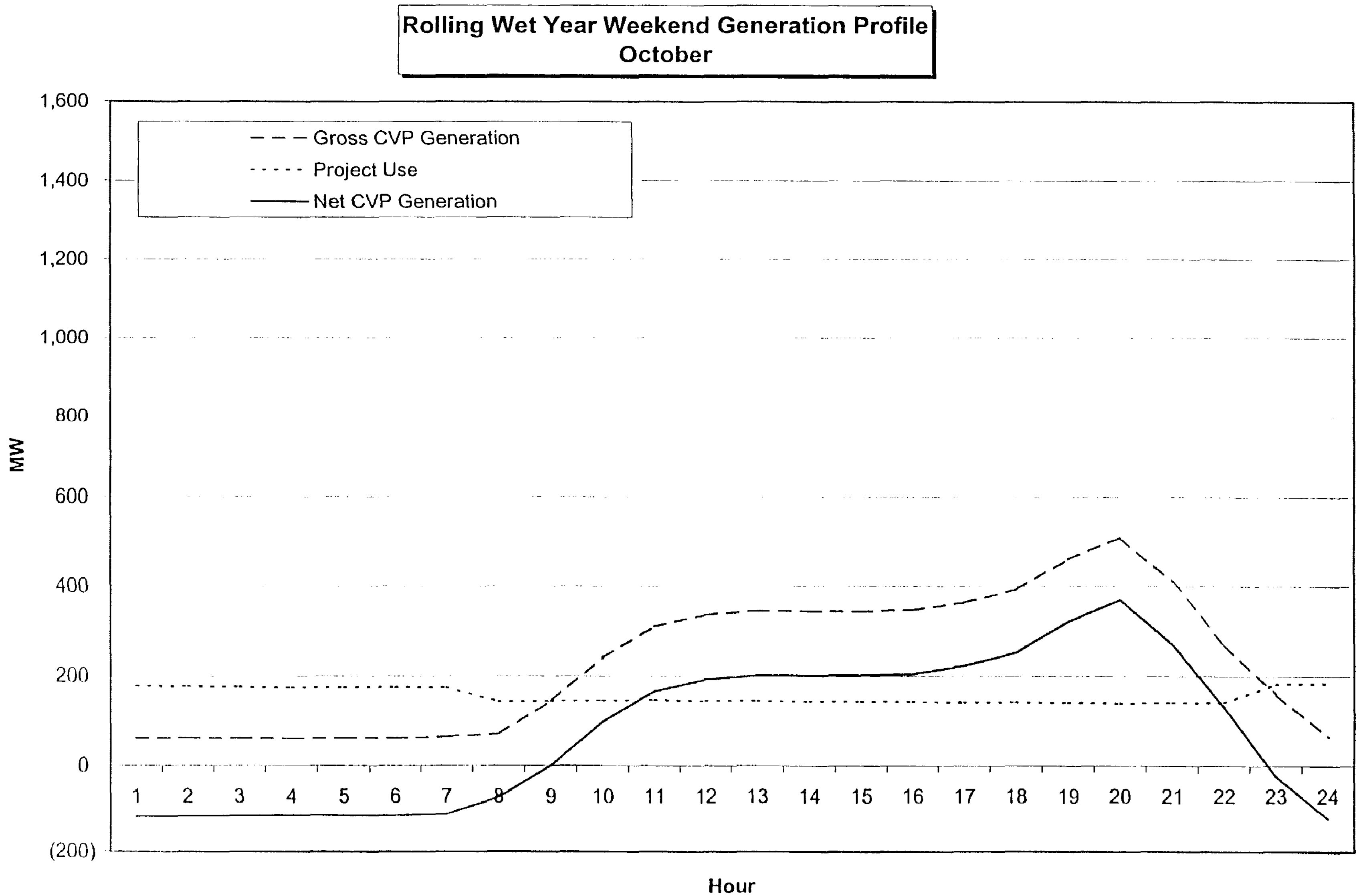
18
19
20
21
22
23
24
Hour

Fig. 12-10


Rolling Wet Year Weekend Generation Profile
October
Gross CVP Generation
Project Use
Net CVP Generation
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1
2
3
4
5
6
7
8
9
10
11
12
13
14
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16
17
18
19
20
21
22
23
24
Hour

Fig. 12-11

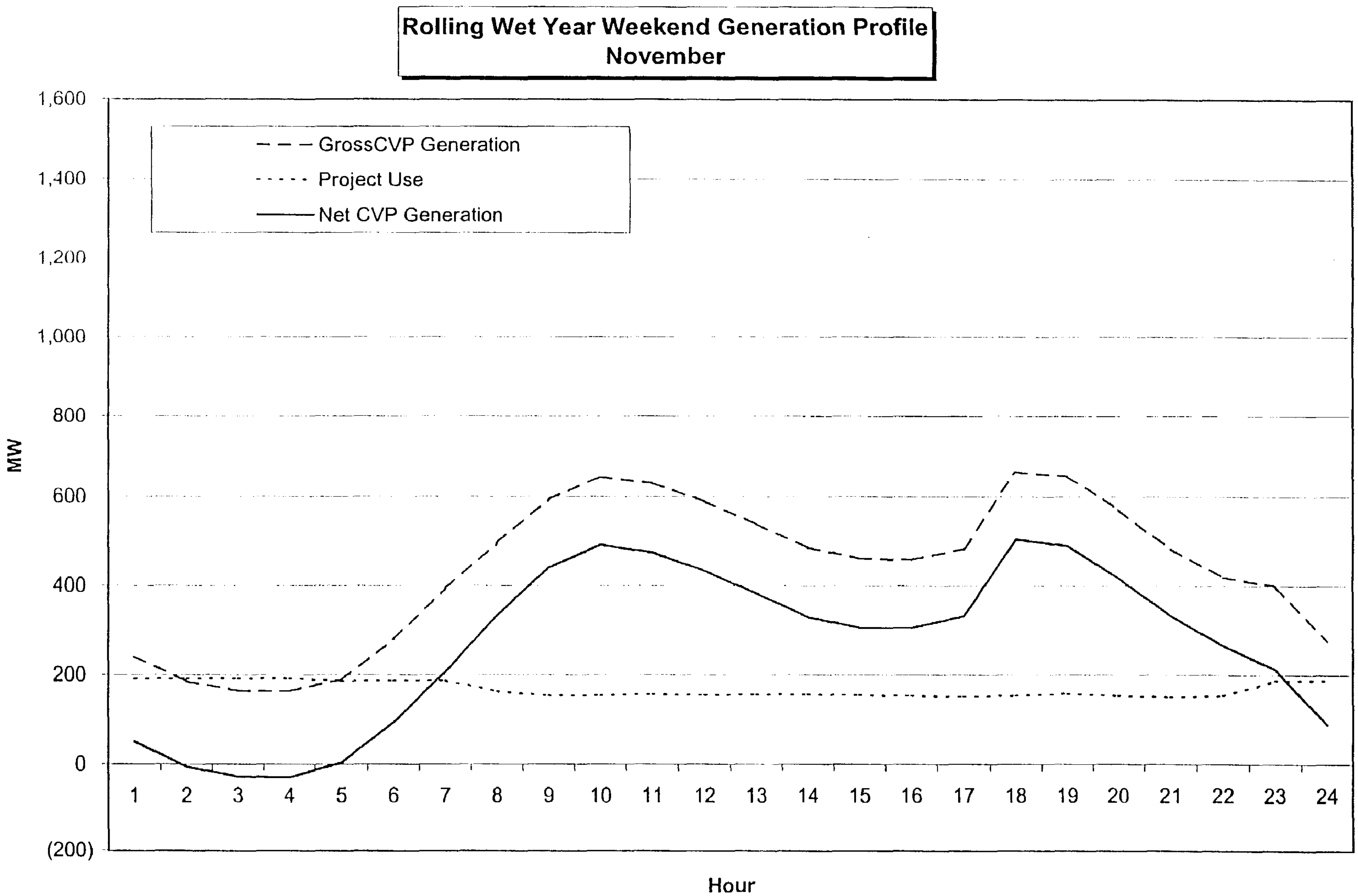
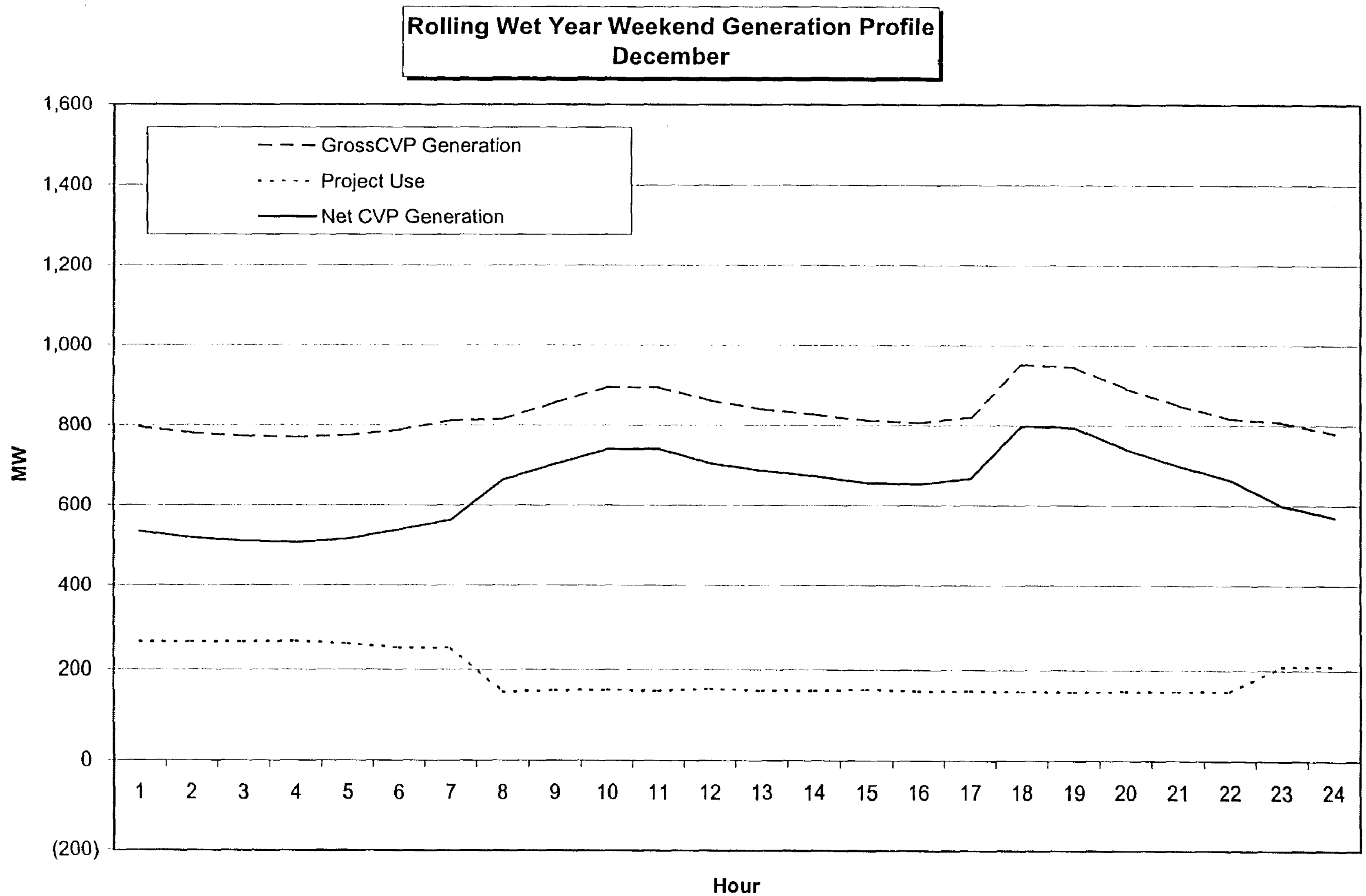

Rolling Wet Year Weekend Generation Profile
November
GrossCVP Generation
Project Use
Net CVP Generation
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
Hour

Fig. 12-12



Rolling Wet Year Weekend Generation Profile
December
GrossCVP Generation
Project Use
Net CVP Generation
1,600
1,400
1,200
1,000
800
600
400
200
0
(200)
MW
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

WESTERN AREA POWER ADMINISTRATION
GENERAL POWER CONTRACT PROVISIONS

Page

*Revised July 10, 1998.

5. Multiple Points of Delivery.

When electric service is supplied at or transmitted to two or more points of delivery under the same rate schedule, said rate schedule shall apply separately to the service supplied at or transmitted to each point of delivery; Provided, That where the meter readings are considered separately, and during abnormal conditions, the Contractor's system is interconnected between points of delivery such that duplication of metered power is possible, the meter readings at each affected point of delivery will be adjusted to compensate for duplication of power demand recorded by meters at alternate points of delivery due to abnormal conditions which are beyond the Contractor's control or temporary conditions caused by scheduled outages.

6. Metering.

6.1. The total electric power and energy supplied or transmitted under the contract will be measured by metering equipment to be furnished and maintained by Western, a designated representative of Western, or by the Contractor. The Contractor shall ensure that metering equipment furnished and maintained by the Contractor or another power supplier, as provided in the contract, meets the metering standards of Western if such metering equipment will be used for billing or other accounting purposes by Western.

6.2. Meters shall be sealed and the seals shall be broken only upon occasions when the meters are to be inspected, tested, or adjusted, and representatives of the interested parties shall be afforded reasonable opportunity to be present upon such occasions. Metering equipment shall be inspected and tested each year by the party responsible for meter maintenance, unless another test interval is agreed upon by the parties. Meters shall also be tested at any reasonable time upon request by either party hereto, a supplemental power supplier, transmission agent, or control area operator. Any metering equipment found to be damaged, defective, or inaccurate shall be repaired and readjusted or replaced by the party responsible for meter maintenance. Meters found with broken seals shall be tested for tampering and, if appropriate, meter readings shall be adjusted by Western pursuant to Provision 6.3 below.

6.3. Except as otherwise provided in Provision 6.4 hereof, should any meter that is needed by Western for billing or other accounting purposes fail to register accurately, the electric power and energy supplied or transmitted during such period of failure to register accurately, shall, for billing purposes, be estimated by Western from the best available information.

6.4. If acceptable inspections and tests of a meter needed by Western for billing or other accounting purposes disclose an error exceeding two percent (2%), then correction based upon the inaccuracy found shall be made of the records of services furnished during the period that such inaccuracy has existed as determined by Western; Provided, That if such period of inaccuracy cannot be determined, correction shall be made for the period beginning with the monthly billing period immediately preceding the billing period during which the test was made.

6.5. Any correction in billing resulting from correction in meter records shall normally be made in the next monthly bill rendered by Western to the Contractor. Payment of such bill shall constitute full adjustment of any claim between the parties hereto arising out of inaccuracy of metering equipment.

7. Existence of Transmission Service Contract.

If the contract provides for Western to furnish services using the facilities of a third party, the obligation of Western shall be subject to and contingent upon the existence of a transmission service contract granting Western rights to use such facilities. If Western acquires or constructs facilities which would enable it to furnish direct service to the Contractor, Western, at its option, may furnish service over its own facilities.

III. RATES, BILLING, AND PAYMENT PROVISIONS.

11. Change of Rates.

Rates applicable under the contract shall be subject to change by Western in accordance with appropriate rate adjustment procedures. If at any time the United States promulgates a rate changing a rate then in effect under the contract, it will promptly notify the Contractor thereof. Rates shall become effective as to the contract as of the effective date of such rate. The Contractor, by written notice to Western within ninety (90) days after the effective date of a rate change, may elect to terminate the service billed by Western under the new rate. Said termination shall be effective on the last day of the billing period requested by the Contractor not later than two (2) years after the effective date of the new rate. Service provided by Western shall be paid for at the new rate regardless of whether the Contractor exercises the option to terminate service.

12. Minimum Seasonal or Annual Capacity Charge.

When the rate in effect under the contract provides for a minimum seasonal or annual capacity charge, a statement of the minimum capacity charge due, if any, shall be included in the bill rendered for service for the last billing period of the service season or contract year as appropriate, adjusted for increases or decreases in the contract rate of delivery and for the number of billing periods during the year or season in which service is not provided. Where multiple points of delivery are involved and the contract rate of delivery is stated to be a maximum aggregate rate of delivery for all points, in determining the minimum seasonal or annual capacity charge due, if any, the monthly capacity charges at the individual points of delivery shall be added together.

13. Billing and Payment.

13.1. Western will issue bills to the Contractor for service furnished during the preceding month within ten (10) days after the end of the billing period.

13.2. If Western is unable to issue a timely monthly bill, it may elect to render an estimated bill for that month to be followed by the final bill. Such estimated bill shall be subject to the same payment provisions as a final bill.

13.3. Payments are due and payable by the Contractor before the close of business on the twentieth (20th) calendar day after the date of issuance of each bill or the next business day thereafter if said day is a Saturday, Sunday, or Federal holiday. Bills shall be considered paid when payment is received by Western; Provided, That payments received by mail will be accepted as timely and without assessment of the charge provided for in Provision 14 (Nonpayment of Bills in Full When Due) if a United States Post Office first class mail postmark indicates the payment was mailed at least three (3) calendar days before the due date.

13.4. Whenever the parties agree, payments due Western by the Contractor may be offset against payments due the Contractor by Western for the sale or exchange of electric power and energy, use of transmission facilities, operation and maintenance of electric facilities, and other services. For services included in net billing procedures, payments due one party in any month shall be offset against payments due the other party in such month, and the resulting net balance shall be paid to the party in whose favor such balance exists. The parties shall exchange such reports and information that either party requires for billing purposes. Net billing shall not be used for any amounts due which are in dispute.

IV. POWER SALES PROVISIONS.

17. Resale of Firm Electric Service (Wholesale Sales for Resale).

The Contractor shall not sell any firm electric power or energy supplied under the contract to any electric utility customer of the Contractor for resale by that utility customer; Provided, That the Contractor may sell the electric power and energy supplied under the contract to its members on condition that said members not sell any of said power and energy to any customer of the member for resale by that customer.

18. Distribution Principles.

The Contractor agrees that the benefits of firm electric power or energy supplied under the contract shall be made available to its consumers at rates that are established at the lowest possible level consistent with sound business principles, and that these rates will be established in an open and public manner. The Contractor further agrees that it will identify the costs of firm electric power or energy supplied under the contract and power from other sources to its consumers upon request. The Contractor will demonstrate compliance with the requirements of this Provision to Western upon request.

19. Contract Subject to Colorado River Compact.

Where the energy sold under the contract is generated from waters of the Colorado River system, the contract is made upon the express condition and with the express covenant that all rights under the contract shall be subject to and controlled by the Colorado River Compact approved by Section 13 (a) of the Boulder Canyon Project Act of December 21, 1928, (45 Stat. 1057) and the parties to the contract shall observe and be subject to and controlled by said Colorado River Compact in the construction, management, and operation of the dams, reservoirs, and powerplants from which electrical energy is to be furnished by Western to the Contractor under the contract, and in the storage, diversion, delivery, and use of water for the generation of electrical energy to be delivered by Western to the Contractor under the contract.

V. FACILITIES PROVISIONS.

20. Design Approval.

All facilities, construction, and installation by the Contractor pursuant to the contract shall be subject to the approval of Western. Facilities interconnections shall normally conform to Western's current "General Requirements for Interconnection," in effect upon the signing of the contract document providing for each interconnection, copies of which are available from Western. At least ninety (90) days, unless otherwise agreed, prior to the date the Contractor proposes to commence construction or to incur an obligation to purchase facilities to be installed pursuant to the contract, whichever date is the earlier, the Contractor shall submit, for the approval of Western, detailed designs, drawings, and specifications of the facilities the Contractor proposes to purchase, construct, and install. The Contractor assumes all risks for construction commenced or obligations to purchase facilities incurred prior to receipt of approval from Western. Western review and approval of designs and construction work in no way implies that Western is certifying that the designs meet the Contractor's needs.

26. Modification of Western Facilities.

Western reserves the right, at any time, to modify its facilities. Western shall keep the Contractor informed of all planned modifications to Western facilities which impact the facilities installation pursuant to the contract. Western shall permit the Contractor to change or modify its facilities, in a manner satisfactory to and at no cost or expense to Western, to retain the facilities interconnection pursuant to the contract. At the Contractor's option, Western shall cooperate with the Contractor in planning alternate arrangements for service which shall be implemented at no cost or expense to Western. The Contractor and Western shall modify the contract, as necessary, to conform to the new facilities arrangements.

27. Transmission Rights.

If the contract involves an installation which sectionalizes a Western transmission line, the Contractor hereby agrees to provide a transmission path to Western across such sectionalizing facilities at no cost or expense to Western. Said transmission path shall be at least equal, in terms of capacity and reliability, to the path in the Western transmission line prior to the installation pursuant to the contract.

28. Construction and Safety Procedures.

28.1. The Contractor hereby acknowledges that it is aware of the hazards inherent in high-voltage electric lines and substations, and hereby assumes full responsibility at all times for the adoption and use of necessary safety measures required to prevent accidental harm to personnel engaged in the construction, inspection, testing, operation, maintenance, replacement, or removal activities of the Contractor pursuant to the contract. The Contractor and the authorized employees, agents, and subcontractors of the Contractor shall comply with all applicable safety laws and building and construction codes, including the provisions of Western's current "Power Systems Safety Manual," "Construction, Safety, and Health Standards," and "Power System Clearance Procedures" in effect upon the signing of the contract; Except, That, in lieu of the safety program required herein, the Contractor may provide sufficient information to demonstrate that the Contractor's safety program is satisfactory to the United States.

28.2. The Contractor and its authorized employees, agents, and subcontractors shall familiarize themselves with the location and character of all the transmission facilities of Western and interconnections of others relating to the work performed by the Contractor under the contract. Prior to starting any construction, installation, or removal work, the Contractor shall submit a plan of procedure to Western which shall indicate the sequence and method of performing the work in a safe manner. No work shall be performed by the Contractor, its employees, agents, or subcontractors until written authorization to proceed is obtained from Western.

28.3. At all times when the Contractor, its employees, agents, or subcontractors are performing activities of any type pursuant to the contract, such activities shall be under supervision of a qualified employee, agent, or subcontractor of the Contractor who shall be authorized to represent the Contractor in all matters pertaining to the activity being performed. The Contractor and Western will keep each other informed of the names of their designated representatives at the site.

28.4. Upon completion of its work, the Contractor shall remove from the vicinity of the right-of-way of the United States all buildings, rubbish, used materials, concrete forms, and other like material belonging to the Contractor or used under the Contractor's direction, and in the event of failure to do so the same may be removed by Western at the expense of the Contractor.

34. Uncontrollable Forces.

Neither party to the contract shall be considered to be in default in performance of any of its obligations under the contract, except to make payment as specified in Provision 13 (Billing and Payment) herein, when a failure of performance shall be due to an uncontrollable force. The term "uncontrollable force" means any cause beyond the control of the party affected, including but not restricted to, failure of or threat of failure of facilities, flood, earthquake, storm, fire, lightning, epidemic, war, riot, civil disturbance or disobedience, labor dispute, labor or material shortage, sabotage, restraint by court order or public authority and action or nonaction by, or failure to obtain the necessary authorizations or approvals from, any governmental agency or authority, which by exercise of due diligence such party could not reasonably have been expected to avoid and which by exercise of due diligence it shall be unable to overcome. Nothing contained herein shall be construed to require a party to settle any strike or labor dispute in which it may be involved. Either party rendered unable to fulfill any of its obligations under the contract by reason of an uncontrollable force shall give prompt written notice of such fact to the other party and shall exercise due diligence to remove such inability with all reasonable dispatch.

35. Liability.

35.1. The Contractor hereby agrees to indemnify and hold harmless the United States, its employees, agents, or contractors, from any loss or damage and from any liability on account of personal injury, death, or property damage, or claims for personal injury, death, or property damage of any nature whatsoever and by whomsoever made arising out of the Contractors', its employees', agents, or subcontractors', construction, operation, maintenance, or replacement activities under the contract.

35.2. The United States is liable only for negligence on the part of its officers and employees in accordance with the Federal Tort Claims Act, as amended.

36. Cooperation of Contracting Parties.

If, in the operation and maintenance of their respective power systems or electrical equipment and the utilization thereof for the purposes of the contract, it becomes necessary by reason of any emergency or extraordinary condition for either party to request the other to furnish personnel, materials, tools, and equipment for the accomplishment thereof, the party so requested shall cooperate with the other and render such assistance as the party so requested may determine to be available. The party making such request, upon receipt of properly itemized bills from the other party, shall reimburse the party rendering such assistance for all costs properly and reasonably incurred by it in such performance, including administrative and general expenses, such costs to be determined on the basis of current charges or rates used in its own operations by the party rendering assistance. Issuance and payment of bills for services provided by Western shall be in accordance with Provisions 13 (Billing and Payment) and 14 (Nonpayment of Bills in Full When Due) herein. Western shall pay bills issued by the Contractor for services provided as soon as the necessary vouchers can be prepared which shall normally be within twenty (20) days.

37. Transfer of Interest in Contract.

37.1. No voluntary transfer of the contract or of the rights of the Contractor under the contract shall be made without the written approval of the Administrator of Western; Provided, That if the Contractor operates a project financed in whole or in part by the Rural Utilities Service, the Contractor may transfer or assign its interest in the contract to the Rural Utilities Service or any other department or agency of the Federal Government without such written approval; Provided further, That any successor to or assignee of the rights of the Contractor, whether by voluntary transfer, judicial sale, foreclosure sale, or otherwise, shall be subject to all the provisions and conditions of the contract to the same extent as though such successor or assignee were the original Contractor under the contract; and, Provided

43. Equal Opportunity Employment Practices.

Section 202 of Executive Order No. 11246, 30 Fed. Reg. 12319 (1965), as amended by Executive Order No. 12086, 43 Fed. Reg. 46501 (1978), which provides, among other things, that the Contractor will not discriminate against any employee or applicant for employment because of race, color, religion, sex, or national origin, is incorporated by reference in the contract.

44. Use of Convict Labor.

The Contractor agrees not to employ any person undergoing sentence of imprisonment in performing the contract except as provided by 18 U.S.C. 4082 (c)(2) and Executive Order 11755, December 29, 1973.